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U.S. DEPARTMENT OF ENERGY

PITTSBURGH ENERGY TECHNOLOGY CENTER

CONTRACT DE-AC22-92PC92159

FOR

# ENGINEERING DEVELOPMENT OF ADVANCED COAL-FIRED LOW-EMISSION BOILER SYSTEMS

SUBMITTED BY:



ABB POWER PLANT LABORATORIES
COMBUSTION ENGINEERING, INC.

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AUGUST 19, 1996

## DISCLAIMER

## DISCLAIMER



PATENT STATUS

Cleared by Chicago OIPC August 6, 1996.

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## EXECUTIVE SUMMARY

### INTRODUCTION

The Pittsburgh Energy Technology center of the U.S. Department of Energy (DOE) has contracted with Combustion Engineering, Inc. (ABB CE) to perform work on the "Engineering Development of Advanced Coal-Fired Low-Emission Boiler Systems" Project and has authorized ABB CE to complete Phase I on a cost-reimbursable basis and Phases II and III on a cost-share basis.

The overall objective of the Project is the expedited commercialization of advanced coal-fired low-emission boiler systems. The specified primary objectives are:

| | Preferred Performance | Minimum Performance |
|---|---|---|
| $NO_X$ Emissions, lb/million Btu | 0.1 | 0.2 |
| *$SO_2$ Emissions, lb/million Btu | 0.1 | 0.2 |
| Particulate Emissions, lb/million Btu | 0.01 | 0.015 |
| Net Plant (HHV) Efficiency, % | 42 | 38 |

*3 lb S/million Btu in the coal

The specific secondary objectives are:

- Improved ash disposability.
- Reduced waste generation.
- Reduced air toxics emissions.

The final deliverables are a design data base that will allow future coal-fired power plants to meet the stated objectives and a preliminary design of a Commercial Generation Unit.

The work in Phase I covered a 24-month period and included system analysis, RD&T Plan formulation, component definition, and preliminary Commercial Generating Unit (CGU) design.

The current Phase II effort covers a 24-month period and includes preliminary Proof-of-Concept Test Facility (POCTF) design and subsystem testing.

Phase III will cover a 6-month period beginning October 1, 1996 and will produce a revised CGU design and a revised POCTF design, cost estimate and a test plan.

Phase IV, the final Phase, will cover a 36-month period and will include POCTF detailed design, construction, testing, and evaluation.

The project will be managed by ABB CE as the contractor and the work will be accomplished and/or guided by this contractor, the DOE Contracting Officer's Representative (COR) and the following team members:

Subcontractors

- ABB Combustion Engineering Systems (ABB ES)
- ABB Environment Systems, Inc. (ABBES)
- Raytheon Engineers and Constructors, Inc. (RE&C)

Consultants

- Dr. Janos Beér, MIT
- Dr. Jon McGowan, U. of Mass.

Advisors

- Association of Edison Illuminating Companies - Power Generation Committee (AEIC)
- Advanced Energy Systems Corporation (AES)
- Black Beauty Coal Company
- Electric Power Research Institute (EPRI)
- Illinois Clean Coal Institute (ICCI)
- Peridot Chemicals, Inc.
- Richmond Power & Light (RP&L)
- Southern Company Services, Inc. (SCS)

**SUMMARY**

The Project is under budget and generally on schedule. The current status is shown in the Milestone Schedule Status Report included as Appendix A. Task 7 - Component Development and Optimization is shown to be slightly behind schedule. Also, addition of Kalina technology will delay completion of Task 8. However, Phase II will be completed on schedule.

Technology transfer activities included writing three technical papers for three conferences (one delivered in this reporting period - Appendix D), submitting a paper abstract for another conference and completing arrangements for a Technical Session for a conference.

Testing in Task 7 - Component Development and Optimization indicated that the gas draft loss across the catalytic CeraMem filter is unacceptably high. A decision to pursue future use of the CeraMem filter will be made early in the next reporting period.

In Task 8 - Preliminary POCTF Design integrating and optimizing the performance and design of the boiler, turbine/generator and heat exchangers of the Kalina cycle is nearly complete. Plant design and licensing activities resumed. A NID system was substituted for the $SNO_X$ Hot Process.

Work was completed in Task 9 - Subsystem Test Design and Plan.

Task 10 - Subsystem Test Unit Construction work is nearly complete. The test rig for the 5,000 acfm CeraMem test has been shipped to the fabricator's shop, inspected, cleaned and will be modified if a decision is made to pursue future use of the CeraMem filter.

Task 11 work on the CeraMem filter was delayed pending a decision on future use of the CeraMem filter. Data analysis for the low-$NO_X$ firing system was completed and a draft report for subtask 11.2 was submitted.

**Plans for the next reporting period** include: a decision on future use of the CeraMem filter, continuing work on the POCTF preliminary design, and report writing.

## TASK 1 - PROJECT PLANNING AND MANAGEMENT

The Project is under budget and generally on schedule. The current status is shown in the Milestone Schedule Status Report included as Appendix A. Task 7 - Component Development and Optimization is shown to be slightly behind schedule. Also, addition of Kalina technology will delay completion of Task 8. However, Phase II will be completed on schedule. All work in Task 1 and all Task 1 deliverables for the reporting period were competed on schedule. All quarterly reports and all monthly Status, Summary, Milestone Schedule Status, and Cost Management reports were submitted on schedule.

Contract Mod A018 (Article H.003 "Limitation of Funds") was received and accepted.

Technology transfer activities consisted of the following:

- A paper titled "ABB's LEBS Activities - A Status Report" was delivered at the First Joint Power & Fuel Systems Contractors Conference.
- A paper titled "ABB's LEBS System Design" was submitted for the Thirteenth Annual International Pittsburgh Coal Conference.
- A paper titled "ABB's LEBS Technologies" was submitted to the '96 International Joint Power Generation Conference (IJPGC).
- Plans were completed for a Technical Session at the '96 IJPGC titled "Systems Developed Under DOE's Combustion 2000 Program".
- An abstract of a paper was submitted for the 1996 American Flame Research Committee International Symposium.

## TASK 7 - COMPONENT DEVELOPMENT AND OPTIMIZATION

### $SNO_X$™ Hot Process

The air pollution abatement system initially recommended for the POCTF was the modified $SNO_X$ Hot Process. The modification consisted of the inclusion of the catalytic CeraMem filter for $NO_X$ reduction and particulate control. The filter, commonly referred to as Cera$NO_X$, was the key technical obstacle towards successful application of the technology. The remaining components of the $SNO_X$ Hot Process have been demonstrated at the Clean Coal Technology Demonstration Facility at Ohio Edison Niles Station and at commercial scale at the NEFO Power Station in Denmark.

Concerns for the Cera$NO_X$ system centered primarily on regeneration, *i.e.*, on-line cleaning, of the filter and filter draft loss. As the $NO_X$ emission target could be met by the burner system alone, subsystem $NO_X$ reduction and $NH_3$ stoichiometry were secondary issues.

Task 7 results, from testing conducted on a 150 ACFM slipstream unit, indicated that the filter could be cleaned effectively (See Appendix B). However, filter draft loss was exceedingly high. Phase I technical and economic analysis indicated that for the Cera$NO_X$ system to be viable, filter draft loss should be less than 12 inches w.c. at process conditions. Task 7 results indicated that the Cera$NO_X$ draft loss would approach 24 inches w.c. at process conditions, and were due in large part to the catalyst application to the filter. Draft loss of the filter alone would approach 8 inches w.c. at process conditions.

It was concluded, based on Task 7 results, that the Cera$NO_X$ filter technology has potential to be effective but was not sufficiently developed for it to be recommended for the POCTF design at this time.

ABB Environmental Systems had developed (outside of the LEBS project) an advanced desulfurization system, called NID, and recommended study of this system as an alternate to the $SNO_X$ Hot Process. The NID process will meet the most stringent LEBS environmental performance objectives. In addition, the NID process integrates well with the Kalina thermal scheme and has the potential for very near term commercialization.

### Low-$NO_X$ Firing System

Completed

## TASK 8 - PRELIMINARY POC TEST FACILITY DESIGN

### Site Selection

In October of 1994 ABB CE formally accepted the Richmond Power & Light (RP&L) offer of Whitewater Valley Unit No. 1 as the host site for the Proof-of-Concept Test Facility (POCTF).

### POCTF/RP&L Project

The proposed POCTF design is a repowering of RP&L Whitewater Valley Unit 1 (WV #1) with the LEBS technologies. Equipment between the coal bunker outlets and stack inlet along with the turbine/generator will be replaced. A listing of the major items of equipment is given in Figure 8-1. The overall project schedule is shown in Figure 8-2.

The key items of performance of the POCTF and a comparison to the existing unit are given in Figure 8-3. While these figures are preliminary, they reflect the substantial efficiency gain of the Kalina cycle and the dramatic reduction in emissions.

### Kalina System Design

The cycle heat balance has been finalized. The design is proceeding with a 2400 psi cycle at 1050 F superheater and 1050 F reheater conditions.

*Boiler*: Surfacing calculations, arrangements of the boiler tubing, headers and interconnecting piping, and the selection of materials has been completed. The air and gas areas of the boiler have been completed and designs are in progress for the major auxiliary equipment to support the boiler operation. The fuel handling and process equipment have been sized and arrangements were prepared to properly interface with the existing equipment.

In parallel with the current boiler design effort, alternative arrangements and configurations are being investigated for optimizing reliability, ease of manufacture, cost impact, and operating conditions. It is anticipated that this work will continue into Subtask 14.1

*Turbine*: A two-case industrial turbine with gear reducer has been selected and configured to conform to the existing turbine pedestal at the RP&L site. The turbine/generator has a capacity of approximately 55 MW gross.

Figure 8-1 - **POCTF/RP&L Project Scope**

**Remove**

- Boiler and Auxilliaries, Piping.
- Combustion Air and Flue Gas Systems.
- Turbine-Generator and Auxilliaries.
- Condensate/Feedwater System.
- Boiler and Turbine Controls.
- Turbine Hall West Wall.
- Miscellaneous Electrical.

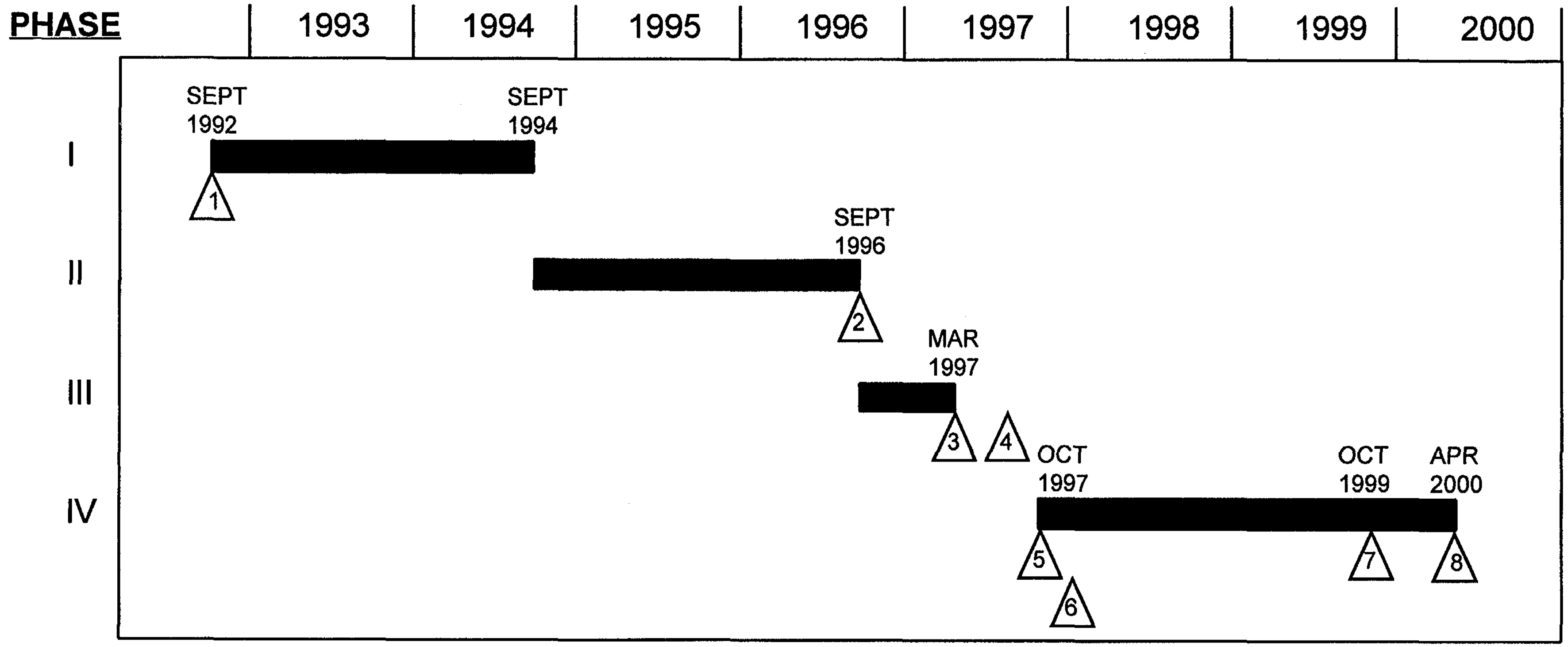
**Modify**

- Cooling Tower.
- Boiler Supports.
- Turbine-Generator Supports.
- Flyash Handling.

**New**

- Boiler and Auxilliaries, Piping.
- Combustion Air and Flue Gas Systems.
- Turbine-Generator and Auxilliaries.
- Condensate/"Feedwater" System.
- Boiler and Turbine Controls.
- Kalina Heat Exchangers.
- Building Extension for same.
- Ammonia Supply, Blowdown, Recovery.
- Air Soot Blowing System.
- Flue Gas Cleanup ($SO_2$ + Particulates).
- FGD Byproduct/Waste System.
- Miscellaneous Electrical.

Figure 8-2 - **POCTF/RP&L Project Schedule**




**MILESTONES**:

1. LEBS contract awarded.
2. Proposal submitted to RP&L.
3. Response from RP&L.
4. Start detailed design.
5. All financing in place. All permits approved.
6. Shutdown Unit 1.
7. Initial operation.
8. Project completion.

# Figure 8-3 - POCTF/RP&L Unit Performance

(Preliminary)

| **THERMAL:** | | **WV#1** | **POCTF** |
|---|---|---|---|
| COAL FIRED | MMBtu/hr | 400 | 440 |
| COOLING TOWER LOAD | MMBtu/hr | 216 | 215 |
| GENERATOR OUTPUT | MW | 35.6 | 54.6 |
| AUXILIARY LOAD | MW | 2.2 | 6.7 |
| NET UNIT GENERATION | MW | 33.4 | 47.9 |
| NET UNIT HEAT RATE | Btu/kWh | 12,000 | 9,200 |
| **ENVIRONMENTAL:** | | **1996/2000** (Regulations) | |
| $SO_2$* | lb/MMBtu | 6.0/1.6 | 0.1-0.2 |
| $NO_x$ | lb/MMBtu | -/0.5 | 0.1-0.2 |
| PARTICULATES | lb/MMBtu | 0.19/0.19 | 0.01 |

* 3 lb S/MM Btu in the coal

The turbine materials selection investigations are continuing with several laboratory test conditions. The remaining turbine / generator interface information for balance of plant design has been developed.

*Heat Exchangers*: Sizing and configuration criteria have been reviewed and evaluated by a manufacturer using heat transfer correlations developed by Exergy. Preliminary cost information was developed and the cost/benefit analysis process was started in order to optimize this portion of the design. Preliminary layout of the exchangers and the configuration of the interconnecting piping has commenced.

## NID Design

NID is the acronym for New Integrated Desulfurization. The NID system integrates the process of gas cooling and $SO_2$ removal into the fabric filter. The NID desulfurization plant is a multi-chamber fabric filter, with each chamber equipped with an independent gas cooling, reagent, and recycle feed system. (See Figure 8-4.)

Flue gas containing particulate and acid gasses is transported to the fabric filter inlet plenum. Gas flow is divided for each compartment and is directed down toward the dust mixing zone. At grade, the gas makes a 180° upward turn. At this point, free-flowing moistened dust containing fresh hydrated lime reagent, recycled fly ash, and partially reacted reagent is mixed into the gas stream. As the gas flows up and into the fabric filter compartment, turbulence causes the gas and moistened dust to mix intimately. Evaporative cooling and reaction of the acid gasses with the reagent take place. The gas then passes through the filter fabric, which retains the moistened/reacted dust, forming a thick, porous cake. Additional acid gas is removed as the gas passes through the highly alkaline filter cake. The clean, cool flue gas then flows from the fabric filter outlet plenum into the outlet duct and to the stack

Particulate is collected with moistened/reacted dust on the surface of the filter bags. When the tubesheet pressure differential reaches a predetermined setpoint, the particulate layer is partially removed by compressed air pulses directed into the bag interior. Each compartment contains many rows of bags, with only one row of bags being cleaned at a time. Thus the compartment remains on line treating flue gas. Some particulate entering the fabric filter compartment will fall directly into the fluidized dust storage hopper. Additional dust is added to the hopper as the filter bags are cleaned. Dust is continuously removed via a rotary air lock located under each hopper. This dust is metered to the dust mixer/conditioner, where controlled quantities of water and dry hydrated lime are added. Water flow to the mixer is controlled by the compartment flue gas outlet temperature and hydrated lime

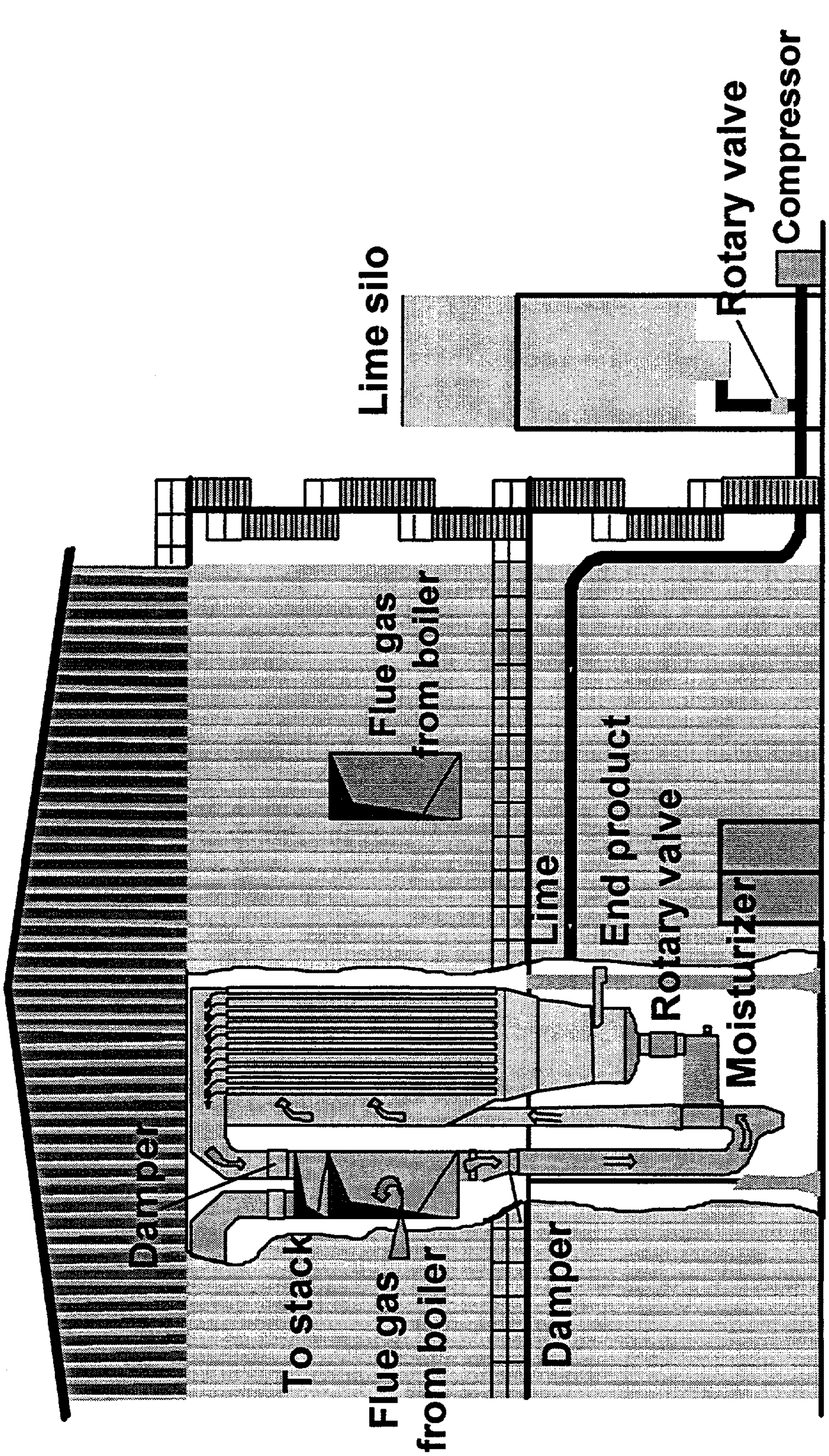



Figure 8-4 - NID System

flow is controlled by the system $SO_2$ removal requirements. The dust is then returned to the inlet of the fabric filter as described above. Excess dust that accumulates in the fabric filter hopper is removed and transported to the ash disposal silo.

Each fabric filter compartment and dust handling system can be individually maintained with the unit operating.

Reagent for the NID system is generally purchased as pebble lime (CaO). The pebble lime is delivered in self unloading trucks that pneumatically transport the lime into the lime storage silo. Pebble lime is metered to the lime hydrator at a controlled rate where water is added to form hydrated lime, $Ca(OH)_2$. A portion of the inert material in the lime is removed and sent to a waste bin by the hydrator. The hydrated lime is transported to the hydrated lime storage silo where it is held for feeding the NID process. Variable speed feeders control the flow of hydrated lime from the silo to the individual dust mixer/conditioners.

The current design of the NID process relies on the use of lime as the reagent. However, preliminary laboratory scale testing with limestone (also conducted outside of the LEBS project) is encouraging and dual reagent capability is planned for the POCTF design.

<u>Plant Design</u> (See Appendix C for a detailed report by Raytheon Engineers & Constructors.)

Sufficient equipment and design information was produced on the major subsystems (vapor generator, turbine-generator, heat exchangers, FGD system) to allow restart of the facility preliminary design. Raytheon's initial project team members were assigned and a walk-down of the site was conducted by their mechanical discipline. A revised schedule for Raytheon's preliminary design activities was developed.

The power cycle process flow diagrams (gas-side heat balance and turbine heat balance) have been developed and are being reviewed.

Work proceeded on the general arrangement drawings, with effort concentrated on development of equipment arrangements in the heat exchanger building.

Work proceeded on the P&ID's. The 12 diagrams for the systems that comprise the power cycle were developed for initial review, and work will now start on the auxiliary/support systems. Initial estimates of pipe and ductwork sizing were developed.

An initial version of the electrical load list was developed, and is being reviewed and refined with the mechanical and controls disciplines. Work was started on some of the electrical equipment specifications. The specification for the distributed control system was drafted and is being reviewed.

Design of the modifications to the turbine pedestal, to accept the new turbine-generator, were prepared and the associated structural analysis is in progress. Work was started on analysis of the boiler foundations and support steel with the new Kalina vapor generator loads.

Work was started on developing the process design for the working fluid treatment, including make-up ammonia and water treatment, cycle fluid physical and chemical treatment, cycle discharge recovery and treatment, and waste fluid treatment.

Due to the extensive demolition work required for the Whitewater Valley Unit 1 to accommodate the Kalina retrofit, this aspect of the project is being developed as a specific engineering activity. Demolition drawings are being prepared, the scope of work is being refined, a demolition specification has been prepared, and the work was reviewed at the station with a demolition contractor.

<u>Licensing</u>

The NEPA Environmental Questionnaire for the POCTF project was revised to incorporate the Kalina cycle and NID and this document is being studied by DOE. Their determinations are expected early in the next reporting period.

Work on the permit applications is continuing. Application forms for the state construction permit were obtained from IDEM, and the application completed and readied for RP&L signature. Further distribution is on hold, pending the results of PETC NEPA review.

## TASK 9 - SUBSYSTEM TEST DESIGN AND PLAN

### $SNO_x$ Hot Process

The final Subtask 9.2 Test Plan was submitted to DOE.

### Low-$NO_x$ Firing System

Completed.

## TASK 10 - SUBSYSTEM TEST UNIT CONSTRUCTION

### $SNO_X$ Hot Process

The test rig for the 5,000 acfm test has been shipped to the fabricator's shop, inspected, cleaned and will be modified to operate under process conditions if a decision is made to pursue future use of the CeraMem filter.

### Low-$NO_X$ Firing System

Completed.

## TASK 11 - SUBSYSTEM TEST OPERATION AND EVALUATION

### $SNO_X$ Hot Process

See Task 7 above.

### Low-$NO_X$ Firing System

*Background*: Data analysis from the combustion testing in the Boiler Simulation Facility (BSF) was completed. The objective of this testing was to evaluate enhancements to the existing TFS 2000™ firing system for improved $NO_X$ emissions performance, while providing the necessary information for supporting the design of the $NO_X$ control subsystem for the POCTF. The LEBS goals to be achieved in this test program were:

- 0.1 lb/MBtu outlet $NO_X$ emissions
- carbon in the fly ash below 5%
- acceptable boiler thermal performance

TFS 2000™ firing system uses a combination of advanced fuel admission assemblies for near-field stoichiometry control, and multiple levels of separated overfire air (global air staging) for control over the bulk staged residence time - stoichiometry history. The integration of fine grind coal, and Concentric Firing System (CFS) auxiliary air nozzles completes the system, maintaining combustion performance and reducing corrosion potential.

*Testing*: For all of the tests performed, a variation of ABB CE's latest coal nozzle tip technology, the Aerotip™, was used. This tip both improves upon the near-field emissions performance, as compared to standard tip designs and minimizes the potential for nozzle tip distortion and deposition that may otherwise occur for problematic (highly slagging coals). A high-sulfur mid-western bituminous coal and a low-sulfur eastern bituminous coal were tested. All tests utilized a high fineness (90% - 200 mesh) coal grind, which is consistent with the TFS 2000™ firing system.

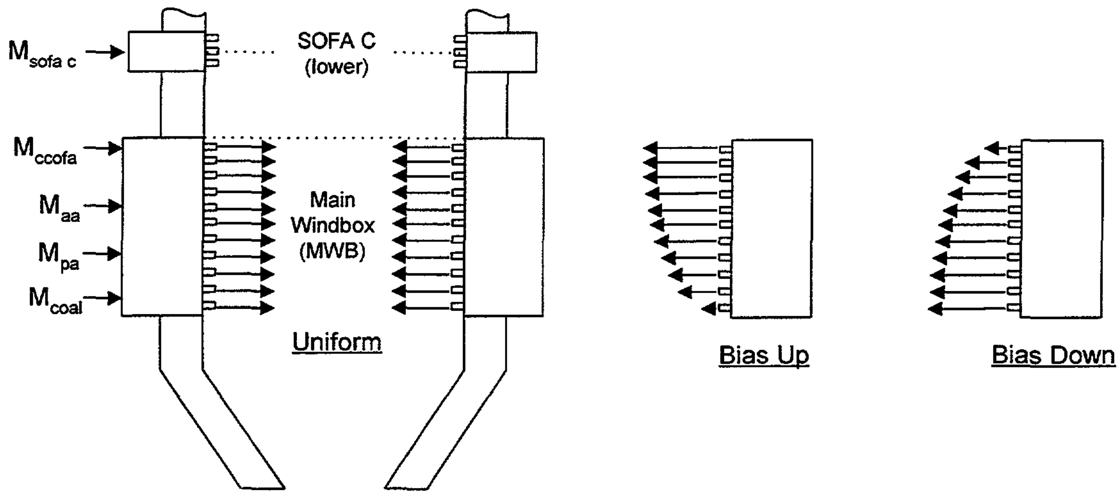
Theoretically, enhancing the performance of existing firing systems through the optimization of coal and secondary air injection into the bulk, main windbox region furnace gases provides for the improvement of the localized substoichiometric combustion, reducing overall furnace $NO_X$ emissions. Extensive CFD modeling conducted under Task 7 aided the selection of promising, enhanced configurations for subsequent combustion testing and the investigation of the fluid mechanics and heat transfer characteristics of the integrated firing systems. In addition, these enhancements were envisioned to provide improvements in $NO_X$ performance at less deeply staged or unstaged conditions, providing a potential alternative to overfire air. Three enhancements to the TFS 2000™ firing system were investigated:

1. Main windbox vertical staging. Vertical control of the combustion process, at each corner of the boiler (Figure 11-1-a.).
2. Horizontal windbox staging. Control of the combustion process, at a given elevation, between the four corners of the boiler (Figure 11-1-b.)
3. Integrated horizontal and vertical staging configuration. The incorporation of both horizontal and vertical combustion process control. For example, a *helical* control arrangement has alternating two-corner firing from the top to bottom of the windbox (Figure 11-2-b.) A *Vertical Coal Bias 1* configuration has four-corner firing at the bottom of the windbox followed by helical two-corner firing (Figure 11-2-c.) The *Vertical Bias 2* configuration has two-corner firing at the top and bottom of the windbox, sandwiching a four-corner coal nozzle arrangement in the middle of the windbox (Figure 11-2-d.)

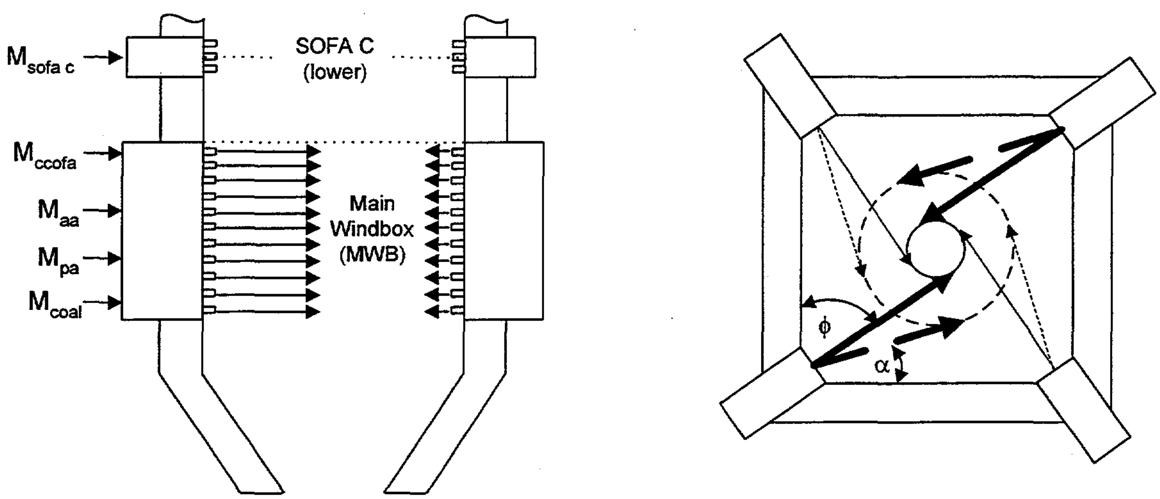
Combustion tests demonstrated the performance of the TFS 2000™ firing system with the Aerotip™ fuel assembly, and tested enhancements to the TFS 2000™ firing system on a LEBS design coal. To support future scale-up of the selected firing system, the effect of residence time on one of the most promising TFS 2000™ firing system enhancements, the helical firing system, was compared to a standard tangential firing system on a second, lower reactivity coal. Standard systems included close-coupled overfire air (CCOFA), a single elevation of separated overfire air (SOFA), and an implementation of TFS 2000™ firing system technology with multiple levels of overfire air. Each of these firing system configurations utilized the same main windbox (MWB) coal and air compartments arrangement. The amount of overfire air (stoichiometry) and the position of the overfire air (residence time), was compared for the different systems.

A schematic of the BSF as configured for the subject work is given in Figure 11-3.

The combustion testing commenced after reaching thermal equilibrium at the desired load. Test variables were set, steady-state operation verified, and positive pressure at the flue duct gas sample point confirmed (to avoid dilution of relevant flue emissions through in-leakage). An ABB MOD 300™ distributed control system (DCS) records global air and fuel input mass flow information, associated temperature data, main burner region windbox air flow rates and total Separated Overfire Air (SOFA) flow rates. The facility data acquisition system and control system allows on-line calculation and control of bulk furnace stoichiometry history. Individual windbox compartment flows, and main and SOFA windbox damper positions were manually recorded.




(a) Main Windbox Vertical Staging



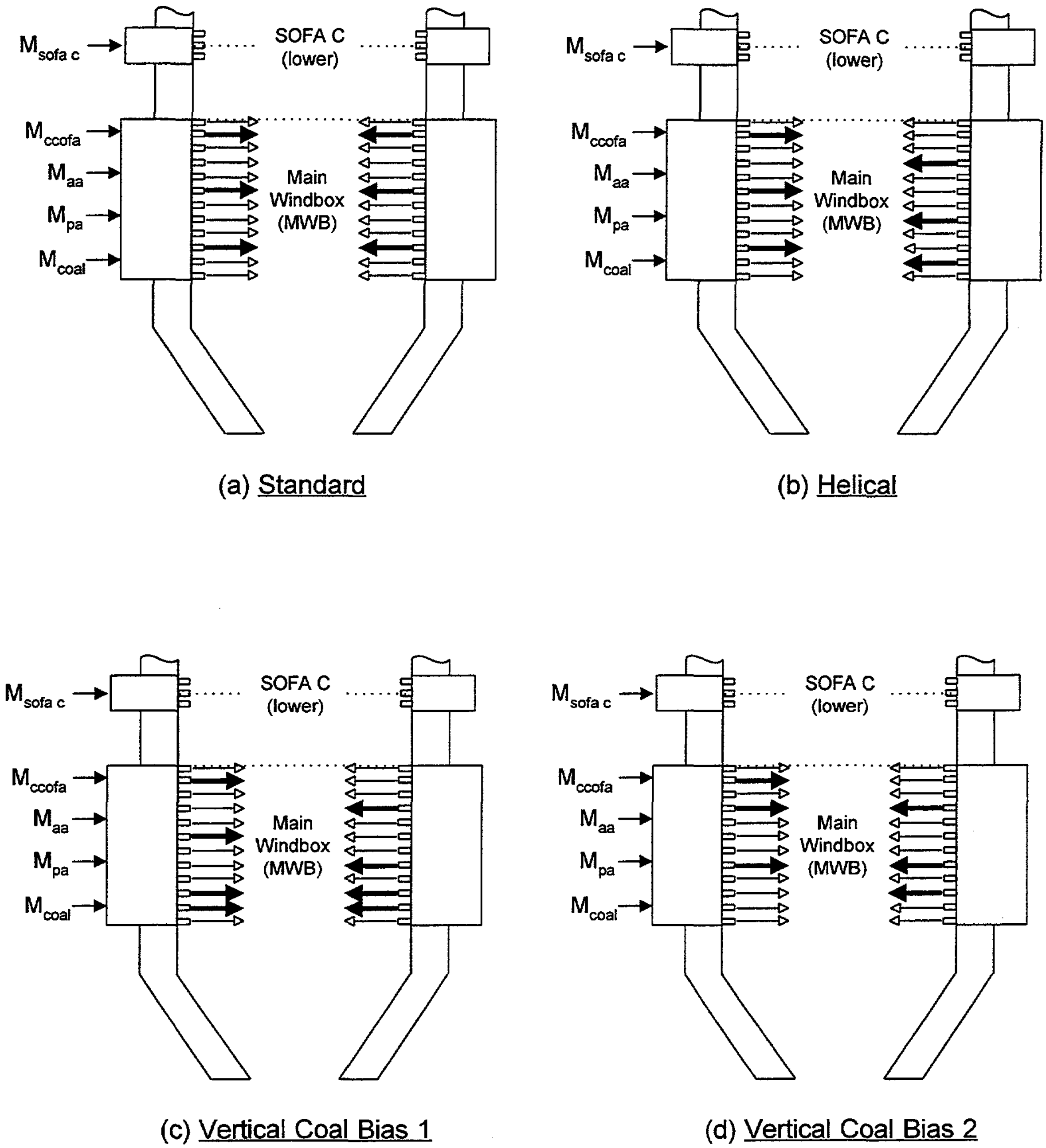

(b) Main Windbox Horizontal Staging

Terminology

sofa = separated overfire air
ccofa = close coupled overfire air
aa = auxiliary air
pa = primary air

$\alpha$ = auxiliary air firing angle
$\phi$ = primary air firing angle

**Figure 11-1** Vertical and Horizontal Staging




<u>Terminology</u>

sofa = separated overfire air
ccofa = close coupled overfire air
aa = auxiliary air
pa = primary air

**Figure 11-2** Integrated Vertical and Horizontal Staging Windbox Configurations

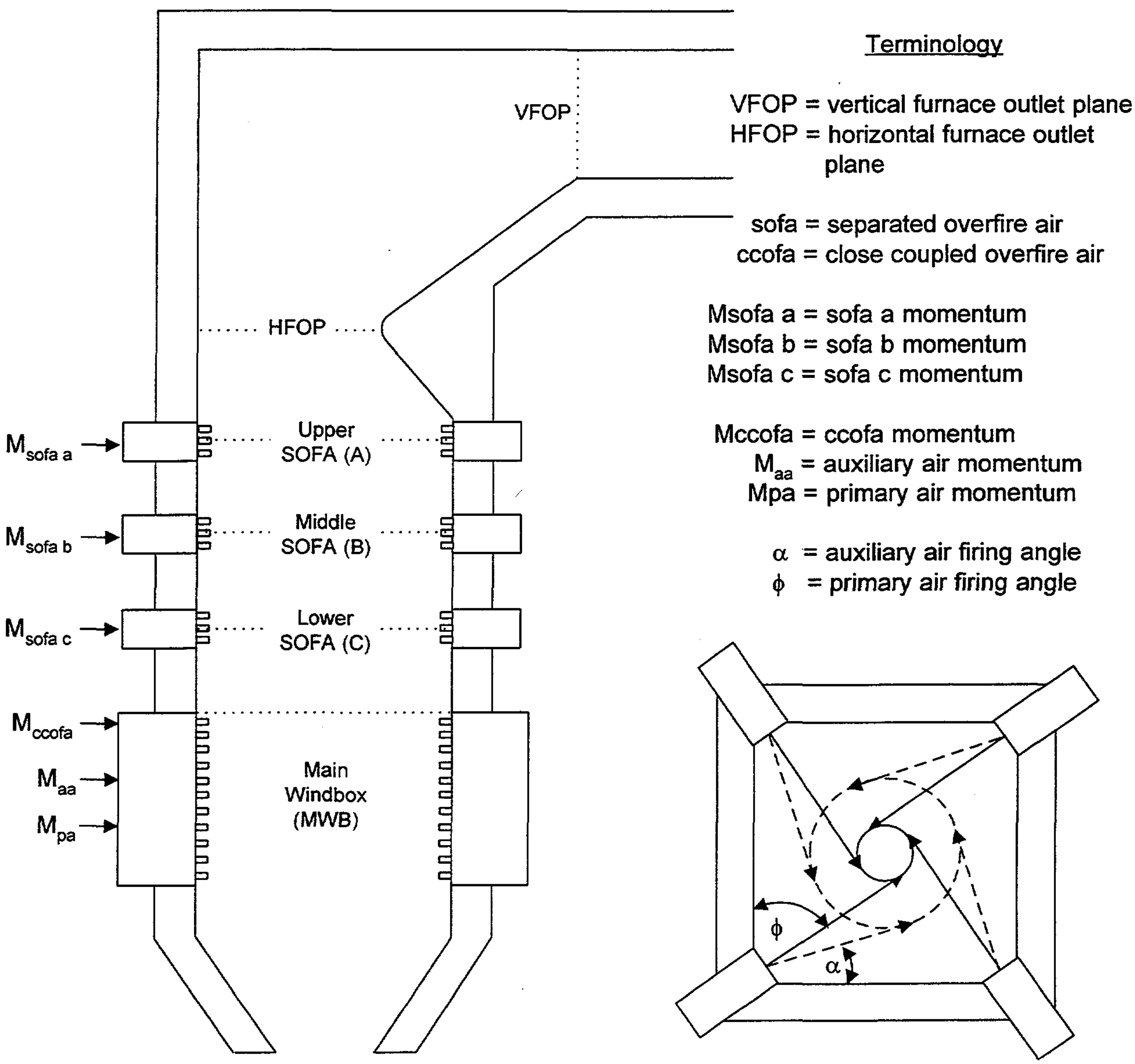



**Figure 11-3** ABB Power Plant Laboratories' Boiler Simulation Facility

A continuous sampling Gas Analysis System (GAS) measures the gaseous species concentrations in the furnace effluent gas stream. The GAS system utilizes state-of-the-art instrument gas species analyzers meeting the requirements of 40 CFR Appendix A methods 7E, 6C, 3A, 10, 25A, and 3A for NO/$NO_X$, $SO_2$, $CO_2$, CO, THC, and $O_2$, respectively. This system was calibrated against certified bottled gas standards approximately every six hours when taking matrix data.

An International Flame Research Foundation water-cooled heat flux probe was used to measure planar (horizontal) total incident heat flux at several locations. Waterwall heat absorption was measured via temperature-controlled, oil-cooled panels used to simulate actual furnace waterwalls. Carbon loss data was obtained through the use of an electrically-heated, water-cooled isokinetic ash sampling probe, roughly fifty feet downstream of the simulated economizer outlet. A high-volume, cyclone equipped sampling probe was used to extract particulate samples from the ash hopper (bottom ash).

For in-furnace species and temperature measurements, a steam-heated, water-cooled gas sampling probe and a water-cooled, suction pyrometer with a single shielded platinum 70% rhodium/platinum 6% rhodium thermocouple (Type B) probe were used. Particulate samples were obtained via a sample probe with a ceramic filter attached.

Two different coals were fired during the BSF combustion testing. The primary test fuel was the high sulfur, mid-western bituminous Viking coal from Montgomery, Indiana. This fuel is one of two coals that is presently fired at the proposed site for the POCTF, and is representative of the class of high sulfur bituminous coals specified for use under the LEBS project. The second test coal, the Ashland coal, is a low sulfur, eastern bituminous coal from West Virginia. This coal was selected as a lower reactivity fuel, as compared to the Viking coal. As-fired analyses of the test Viking and Ashland coals are given in Table 11-1.

Experimental data from the BSF testing included global firing system configuration information, emissions results and overfire air distribution. In all, 110 combustion tests were performed. Operation and design variables examined in the bench marking and enhancement test process included:

- Global residence time (OFA elevation)
- Global stoichiometry (OFA quantity)
- Local residence time / stoichiometry (mixing) history
- Secondary air yaw (horizontal divergence) angle
- Separated overfire air tilt
- Excess $O_2$ (final stoichiometry)
- Fuel air quantity
- Coal type

Table 11.1 1995/1996 LEBS BSF Test Coals

| | Viking | | Ashland |
|---|---|---|---|
| **Proximate:** | | | |
| VM | 34.5% | | 25.8% |
| FC | 52.0 | | 63.0 |
| FC/VM | 1.51 | | 2.44 |
| HHV | 12,624 | | 13.506 |
| **Ultimate:** | | | |
| Moisture | 4.0% | (est) | 1.7% |
| Hydrogen | 4.7% | | 4.0% |
| Carbon | 70.4% | | 76.6% |
| Sulfur | 2.4% | | 0.8% |
| Nitrogen | 1.4% | | 1.2% |
| Oxygen | 7.6% | | 6.3% |
| Ash | 9.5% | | 9.6% |
| Total | 100.0% | | 100.2% |
| O/N | 5.27 | | 5.25 |
| lb N/MBtu | 1.14 | | 0.89 |
| **Ash Fusibility** | Reducing Atmosphere | | Reducing Atmosphere |
| I.T. | 2,090 | F | +2,700 F |
| S.T. | 2,250 | F | +2,700 F |
| H.T. | 2,340 | F | +2,700 F |
| F.T. | 2,420 | F | +2,700 F |
| DIFF. (F.T. - I.T.) | 330 | | na F |
| **Particle Size** | | | |
| Mesh Size | Retained | | Retained |
| +50 | 0.0% | | 0.0% |
| +70 | 0.2% | | 0.0% |
| +100 | 0.7% | | 0.6% |
| +200 | 8.7% | | 6.7% |
| -200 | 90.3% | | 92.7% |
| Total | 99.9% | | 100.0% |

*Results and Analysis:* A summary of the results from testing various firing system configurations on the Viking coal are given in Figure 11-4. All emissions data is corrected to 3% excess oxygen. As can be seen, significant reductions in $NO_X$ emissions are found through the implementation of the present $NO_X$ control technologies. Beginning with $NO_X$ emissions of 0.59 lb/MBtu with a typical "baseline" (post-NSPS) firing system arrangement, $NO_X$ emissions were reduced to 0.13 lb/MBtu for an "optimized" TFS 2000™ firing system arrangement and eventually to a low of 0.11 lb/MBtu. As expected, carbon in the fly ash increased as the level of global air staging was increased, but was less than or equal to the performance limit of 5%. There were no adverse impacts on boiler thermal performance.

From the fundamental scale testing carried out under Task 7 changes in the vertical stoichiometry distribution within the main burner zone (at similar overall global stoichiometry histories) were shown to affect outlet $NO_X$ emissions. Testing in the BSF verified the importance of vertical windbox stoichiometry control. Starting at an outlet $NO_X$ level of 0.14 lb/MBtu for a pre-optimized TFS 2000™ configuration, $NO_X$ emissions rose to .17 and .16 lb/MBtu as secondary air was biased vertically (up and down, respectively), altering the windbox stoichiometry. The apparent detrimental effect of vertical staging reflects the fact that the TFS 2000™ firing system is "optimized" with respect to vertical stoichiometry distribution.

Through adjustments of the split in the quantities of overfire air, the initial 0.14 lb/MBtu outlet $NO_X$ levels for the TFS 2000™ configuration were reduced to 0.13 lb/MBtu on Viking coal. Fired on Ashland coal, the $NO_X$ measured 0.15 lb/MBtu. This "optimized" (without enhancements) TFS 2000™ firing system (Figure 11-5) is the basis for comparison with the vertical, horizontal and combined enhancement (helical) firing system.

Figure 11-6 shows the effect of a horizontal bias in coal on outlet NOx emissions. The tests represent a transition from standard, four-corner coal firing, (indicated as *Opt. TFS 2000™*), to opposed two-corner coal firing, (indicated as *Coal Bias 3*). For these tests, a uniform (25% per corner) horizontal air split was maintained among the four main windboxes. The plan area of the furnace is rectangular. Therefore, during the horizontal testing, "diagonal symmetry" was maintained in the division of air and fuel for all test cases, (*i.e.*, the left front and right rear corners were identically configured; similarly, the right front and left rear windbox configurations were identical).

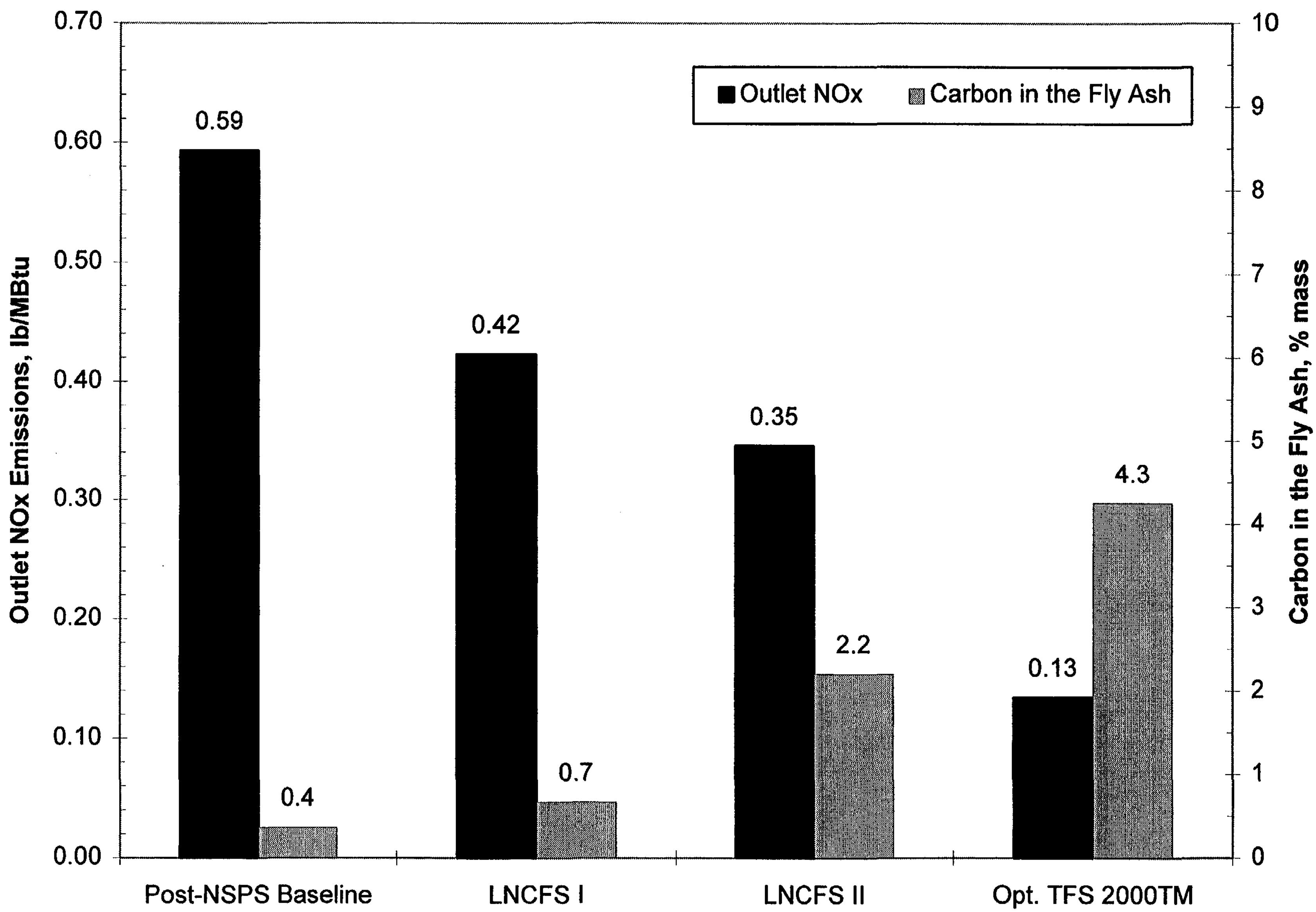



**Figure 11-4** ABB CE Low NOx Tangential Firing Systems (Viking Coal)

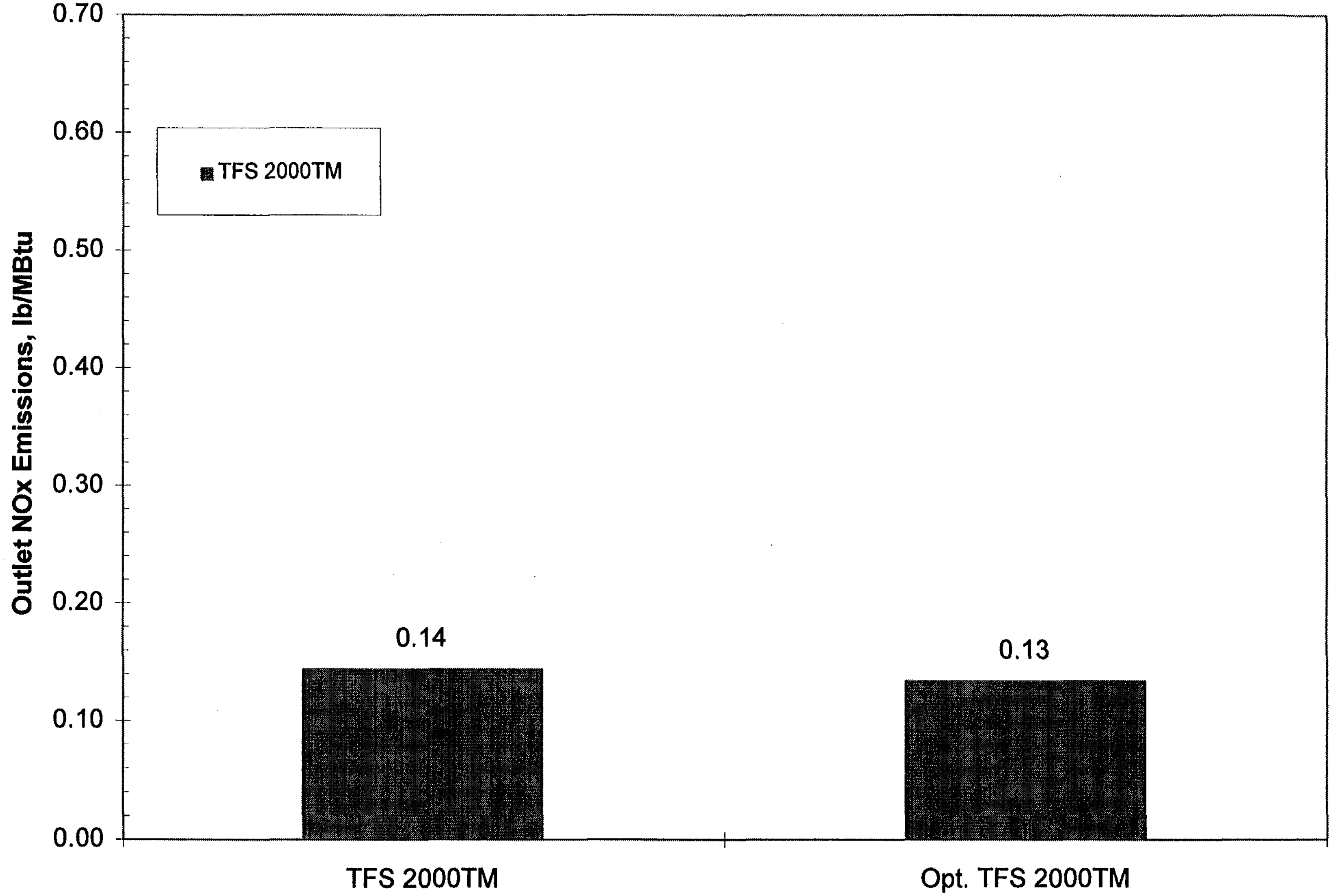



**Figure 11-5** Optimized TFS 2000$^{TM}$ Firing System: SOFA A and C (Viking Coal)

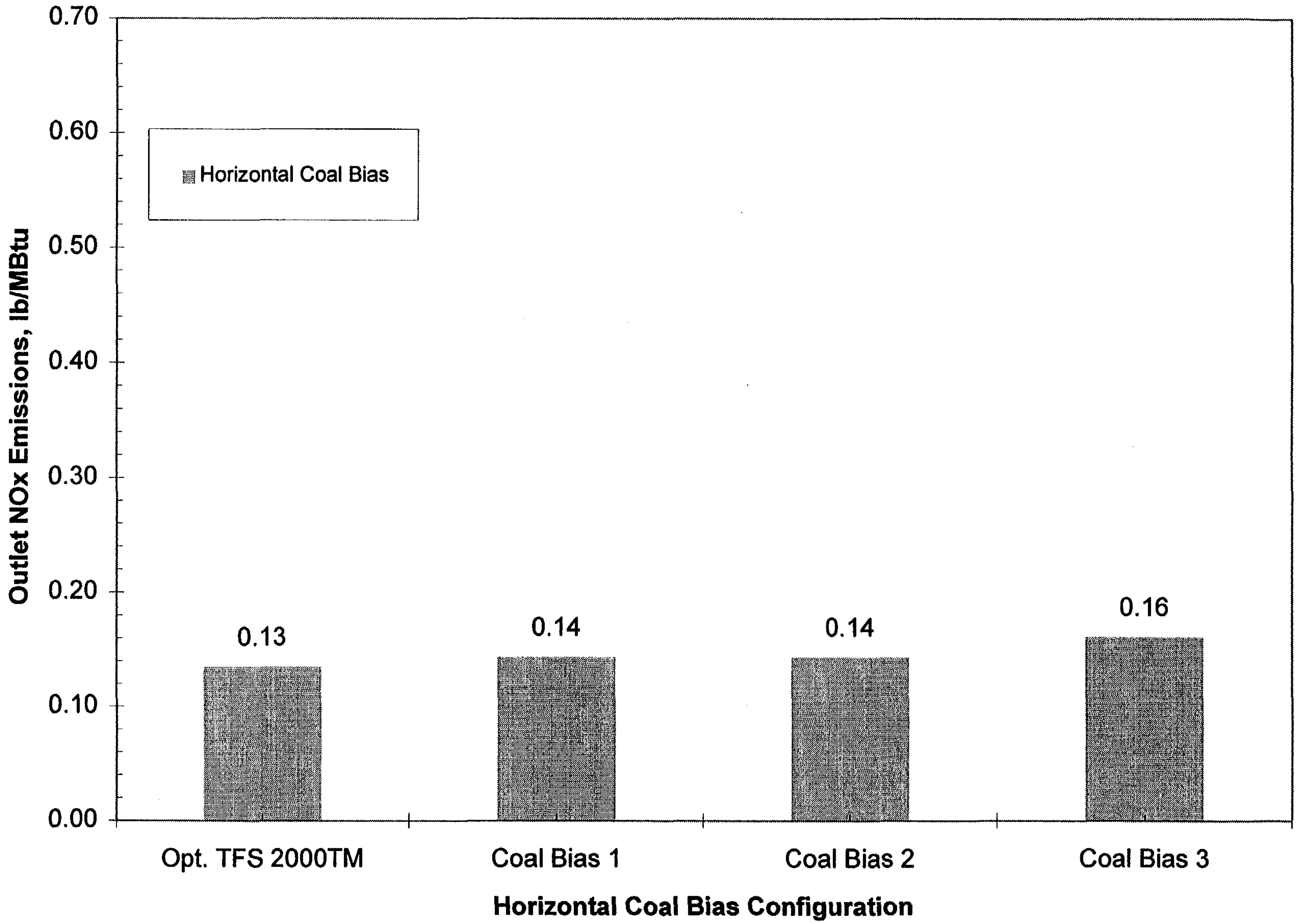



**Figure 11-6** Main Windbox Horizontal Coal Bias: SOFA A and C (Viking Coal)

Horizontal coal biasing places adjacent windboxes at different, collective stoichiometries, affecting the "mid-field" $NO_X$ formation and reduction potential. Two-corner firing maximizes the residence time for horizontal staging. As shown in Figure 11-6, the effect of changing the horizontal coal distribution was to increase $NO_X$ emissions in comparison to the optimized TFS 2000™ configuration. Beginning with moderate horizontal coal staging, $NO_X$ emissions measured 0.14 lb/MBtu, a modest increase from the optimized TFS 2000™ levels. However, with a two-corner coal firing configuration, or "maximum" horizontal coal bias, $NO_X$ emissions increased to 0.16 lb/MBtu. In this configuration the two coal-firing corners each fired 50% of the coal with 25% of the air. Referring to Table 11-3, this resulted in very low corner-based stoichiometries for the coal biased cases, which likely contributed to the observed rise in overall $NO_X$ levels.

Table 11-3 Main Burner Zone Horiz. Coal Staging Test Results: SOFA A & C

| Test Number | 31.1 | 32 | 33 | 34 |
|---|---|---|---|---|
| Description | TFS 2000™ | Coal Bias 1 | Coal Bias 2 | Coal Bias 3 |
| SOFA Configuration | SOFA AC | SOFA AC | SOFA AC | SOFA AC |
| Vertical (Planar) main burner zone $\phi$ | 0.69 | 0.73 | 0.74 | 0.74 |
| Left Front/ Right Rear | 0.75 | 1.08 | 1.75 | na |
| Right Front/ Left Rear | 0.61 | 0.55 | 0.52 | 0.47 |
| Outlet $NO_X$, lb/MBtu | 0.13 | 0.14 | 0.14 | 0.16 |

Additional testing was performed to redistribute the air in the four windboxes to optimize the two-corner coal firing. From Figure 11-7, it can be seen that $NO_X$ emissions decrease slightly by redistributing the air for the two-corner coal case. Starting with emissions of 0.16 lb/MBtu for a uniform, four-corner air split, $NO_X$ levels fell to 0.15 lb/MBtu for the *Air Bias 4a* configuration. In this configuration, all of the available auxiliary air is injected through two corners, and all of the coal (including the primary air and a prescribed quantity of fuel air) is injected through the opposite two. Though improved over the horizontal coal-biased, uniform air tests, these $NO_X$ levels are still higher than those from the optimized TFS 2000™ firing system. The best horizontal staging configuration was tested under high excess $O_2$ (4.5%) conditions (*Air Bias 3* and *Air Bias 4*; tests 40.1 and 34.3 as shown in Table 11-4), as well as nominal excess $O_2$, (2.5%) test 34.3 (shown as *Air Bias 4a*, or test *34.4*). $NO_X$ levels did not approach the optimized TFS 2000™ firing system.

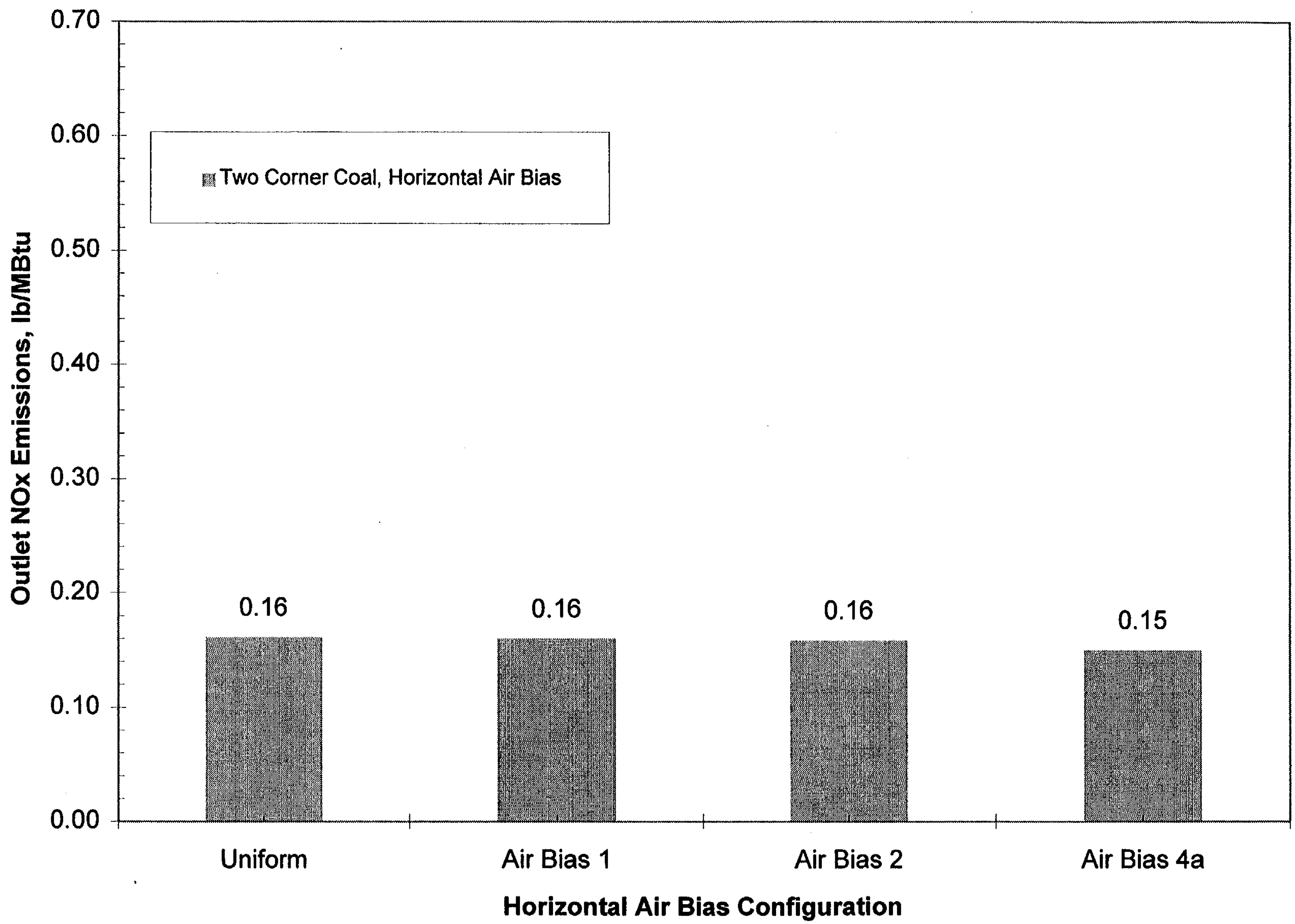



**Figure 11-7** Main Windbox Horizontal Air Bias: SOFA A and C (Viking Coal)

Table 11-4 Main Burner Zone Horiz. Air and Coal Staging Test Results: SOFA A & C

| Test Number | 34 | 34.1 | 34.2 | *40.1* | *34.3* | 34.4 |
|---|---|---|---|---|---|---|
| Description | Uniform Air | Air Bias 1 | Air Bias 2 | *Air Bias 3* | *Air Bias 4* | Air Bias 4a |
| SOFA Configuration | SOFA AC | SOFA AC | SOFA AC | *SOFA AC* | *SOFA AC* | SOFA AC |
| Vertical (Planar) main burner zone $\phi$ | 0.74 | 0.70 | 0.71 | *0.80* | *0.85* | 0.78 |
| Left Front/ Right Rear | na | na | na | *na* | *na* | na |
| Right Front/ Left Rear | 0.47 | 0.46 | 0.50 | *0.71* | *0.27* | 0.27 |
| Outlet $NO_X$, lb/MBtu | 0.16 | 0.16 | 0.16 | *0.22* | *0.22* | 0.15 |

Finally, the best vertical and best horizontal systems strategies were combined in the *helical* coal firing configuration. The helical firing configuration (refer to Figure 11-2), creates a more uniform vertical and horizontal stoichiometry history within the main burner zone. A comparison of the helical to the TFS 2000™ firing system configuration for $NO_X$ emissions is given in Figure 11-8 and summarized in Table 11-5. On the Viking coal, helical firing produced NOx emissions of 0.13 lb/MBtu, equivalent to the TFS 2000™ firing system. Fired on a more challenging low $NO_X$, Ashland coal, the $NO_X$ emissions, shown in Figure 11-9 and Table 11-6, were 0.14 lb/MBtu for the helical arrangement, in comparison to 0.15 lb/MBtu for the TFS 2000™ firing system.

Changing the horizontal stoichiometry distribution by biasing the secondary air within the main burner zone produced an increase in $NO_X$ over the uniform air distribution, helical configuration, repeating the results from the horizontal staging alone. However, redistributing the close coupled overfire air (CCOFA), at the top of the windbox, air from four corners to two corners, dropped the outlet $NO_X$ emissions to 0.12 lb/MBtu (Viking Coal), slightly lower than those from the optimized TFS 2000™ system.

The lowest $NO_X$ (0.11 lb/MBtu), was obtained with the Vertical Coal Bias 1 configuration, four-corner firing at the bottom of the windbox and a helical (alternating 2-corner coal firing), for the remainder of the windbox. Slightly lower than normal excess air levels (2.1 % $O_2$ versus nominal 2.5%), contributed to the $NO_x$ improvement over the TFS 2000™ firing system.

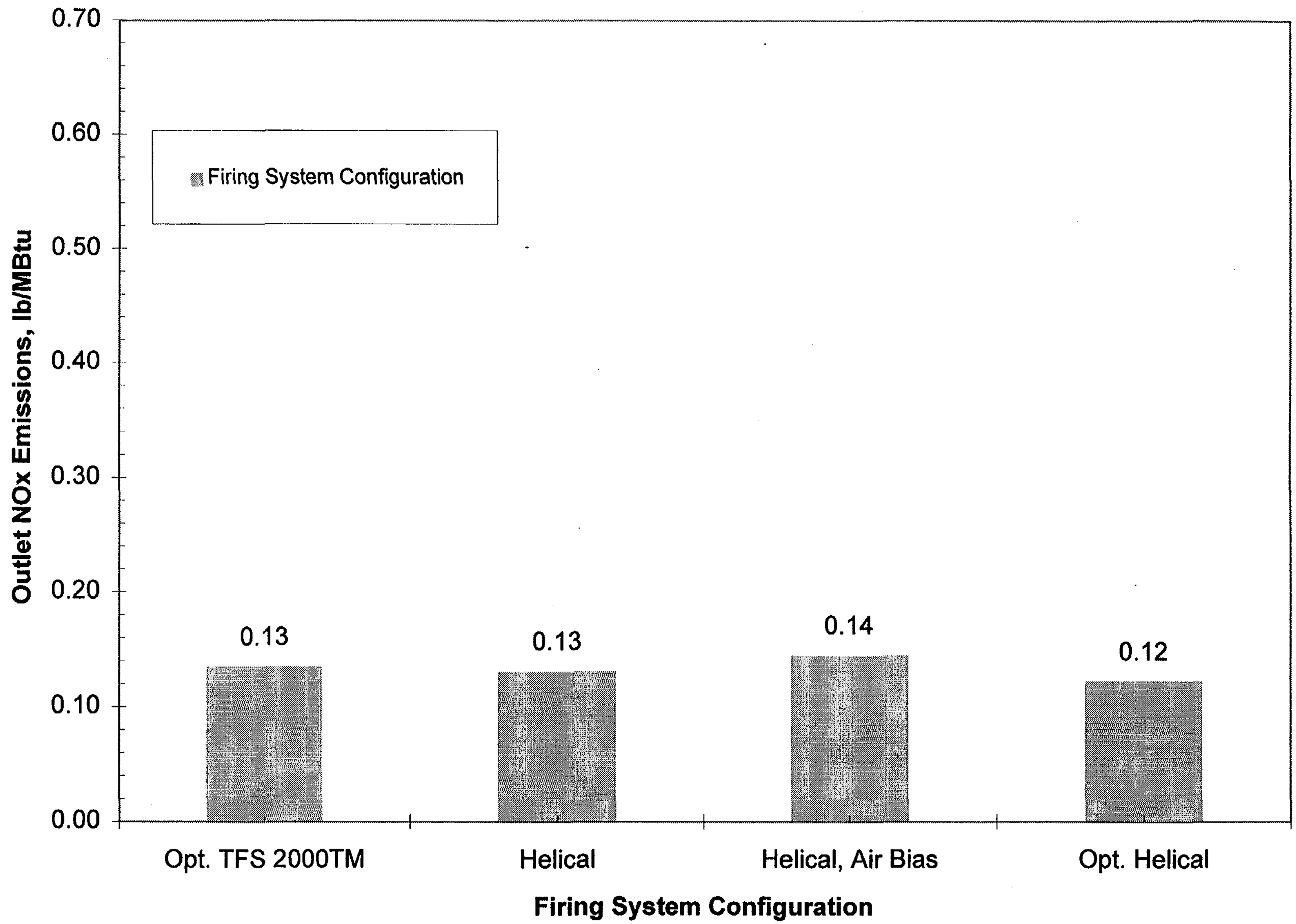



**Figure 11-8** Helical Firing System: SOFA A and C (Viking Coal)

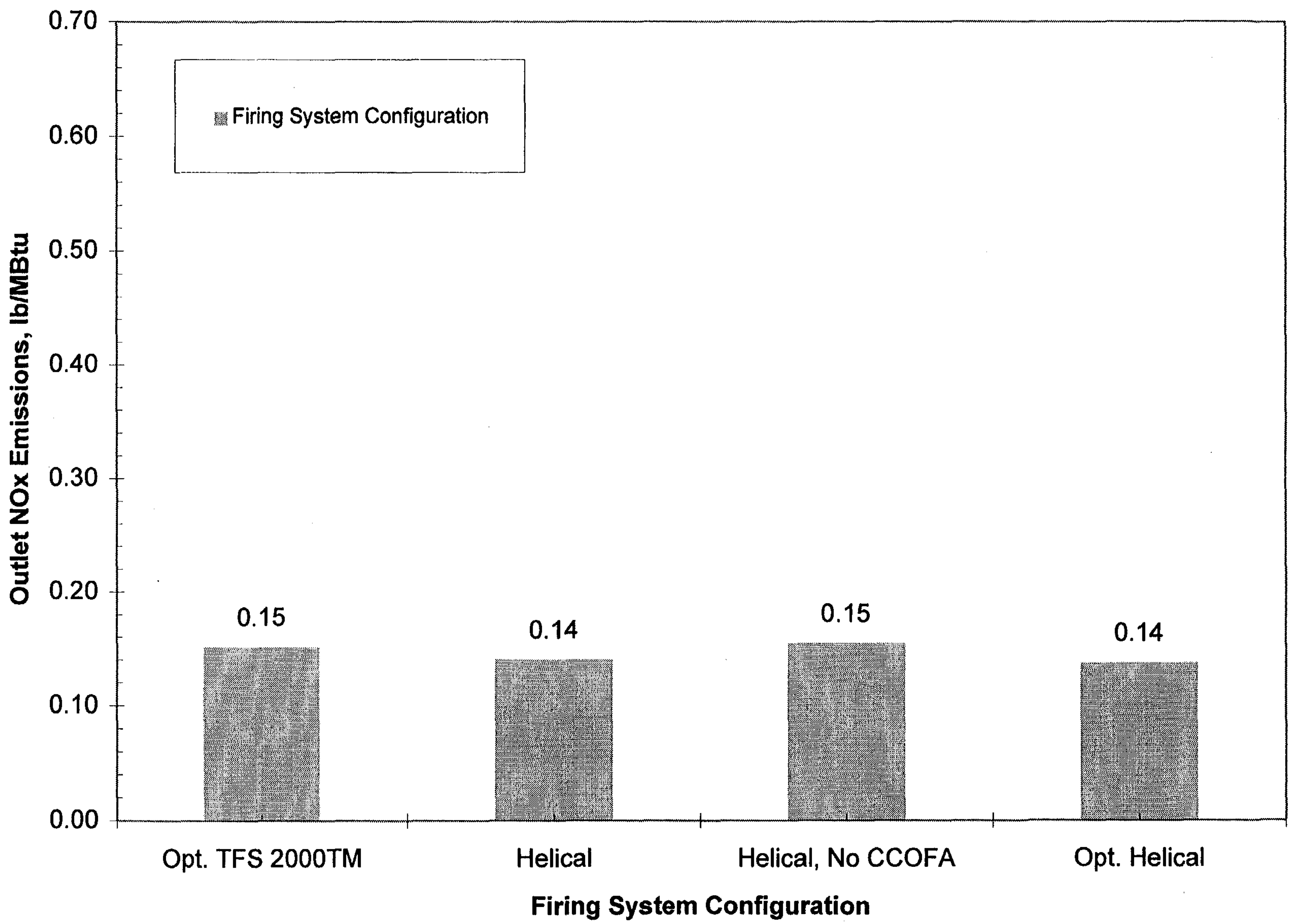



**Figure 11-9** Firing System Enhancements: SOFA A and C (Ashland Coal)

Table 11-5 Firing System Enhancement Testing: SOFA's A & C, Viking Coal

| Test # | Firing System Configuration | $NO_X$, lb/MBtu | $\Delta NO_X$, %* |
|---|---|---|---|
| 11 | TFS 2000™ | 0.14 | +11.8 |
| 14 | Vertical Air Bias 1 | 0.16 | +17.4 |
| 15 | Vertical Air Bias 2 | 0.17 | +27.8 |
| 31.1 | Optimized TFS 2000™ | 0.13 | - |
| 32 | Horizontal Coal Bias 1 | 0.14 | +6.4 |
| 33 | Horizontal Coal Bias 2 | 0.14 | +6.2 |
| 34 | Horizontal Coal Bias 3 | 0.16 | +19.5 |
| 34.1 | Two Corner Coal, Air Bias 1 | 0.16 | +18.6 |
| 34.2 | Two Corner Coal, Air Bias 2 | 0.16 | +17.7 |
| 34.4 | Two Corner Coal, Two Corner Air | 0.15 | +11.4 |
| 40.1 | Two Windbox Firing | 0.22 | +63.2 |
| 37.2 | Helical | 0.13 | -3.1 |
| 37 | Helical, Horizontal Air Bias | 0.14 | +7.4 |
| 38 | Optimized Helical (Two Corner CCOFA) | 0.12 | -9.3 |
| 38.1 | Optimized Helical, Vertical Coal Bias I | 0.11 | -15.3 |

*Compared to 0.13 for Optimized TFS 2000™

Table 11-6 Firing System Enhancement Testing: SOFA's A & C: Ashland Coal

| Test # | Firing System Configuration | $NO_X$, lb/MBtu | $\Delta NO_X$, %* |
|---|---|---|---|
| 51 | Optimized TFS 2000™ | 0.15 | - |
| 52 | Helical | 0.14 | -7.6 |
| 53 | Helical, No CCOFA | 0.15 | 1.9 |
| 54 | Opt. Helical (Two Corner CCOFA) | 0.14 | -9.3 |
| 54.1 | Opt. Helical (Two Corner CCOFA) | 0.13 | -12.1 |

*Compared to Optimized TFS 2000™

$NO_X$ and carbon in the fly ash (CIFA) are also a function of excess oxygen concentration. Excess oxygen levels were generally maintained at a nominal 2.5% $0_2$. For the test program, Figure 11-10, shows TFS 2000™ $NO_X$ and CIFA results. As expected, $NO_X$ emissions increase as excess oxygen rises, consistent with thermal NOx formation. By the same reasoning, increasing the amount of excess oxygen provided for more complete combustion and the decreased levels of carbon in the fly ash as shown.

Figures 11-11 and 11-12 summarize the results of the TFS 2000™ firing system enhancements on the Viking and Ashland coals, respectively. Only the optimized helical configuration provided a slight (0.01-0.02 lb/MBtu) improvement over the TFS 2000™ firing system at the minimum $NO_X$ conditions.

Clearly, the absolute levels of $NO_X$ emissions are dominated by the global stoichiometry irrespective of the tested firing system geometry. This point is important as it emphasizes that for an overall, optimized, global stoichiometry history, significant latitude can be exercised in the design of the firing system without appreciably affecting $NO_X$ emissions performance. This "robust" performance is a significant advantage of tangential firing systems such as the TFS 2000™ firing system since it implies that the design of the firing system can focus more on the global process, and less on the tuning of individual burner assemblies.

The subsequent work focused on further testing of standard tangential and the helical firing systems, with respect to further optimizing the global staging residence time.

*Additional Testing and Results:* In addition to the TFS 2000™ firing system enhancement evaluations, results were compared to standard, globally-staged, firing systems with varying overfire air residence times, in order to provide a balanced view of the performance of the enhancements and to support future scale-up of the "best" performing system. Using the Viking coal, the bulk main burner zone stoichiometry was varied for several overfire air configurations (Table 11-7), and compared to the integrated vertical and horizontal (helical) arrangement performance. A global process with a higher main burner zone stoichiometry, achieved through the optimization of local staging, will provide a less corrosive environment.

The TFS 2000™ firing system and all of the vertical, horizontal and combined helical enhancements tested utilized separated overfire air (SOFA) elevations A and C, the upper and lower overfire air (OFA) elevations available. An additional two-SOFA configuration is comprised of a combination of SOFA's B & C (two elevations, compressed together and providing a shorter residence time than SOFA's A & C). This SOFA B & C configuration is effectively a TFS 2000™ type system for small utility or industrial boiler applications, where physical limitations may exist in practical staged-residence times. Further enhancement testing was subsequently performed with SOFA elevations B and C independently, the middle and lower SOFA elevations. The lowest furnace outlet $NO_X$

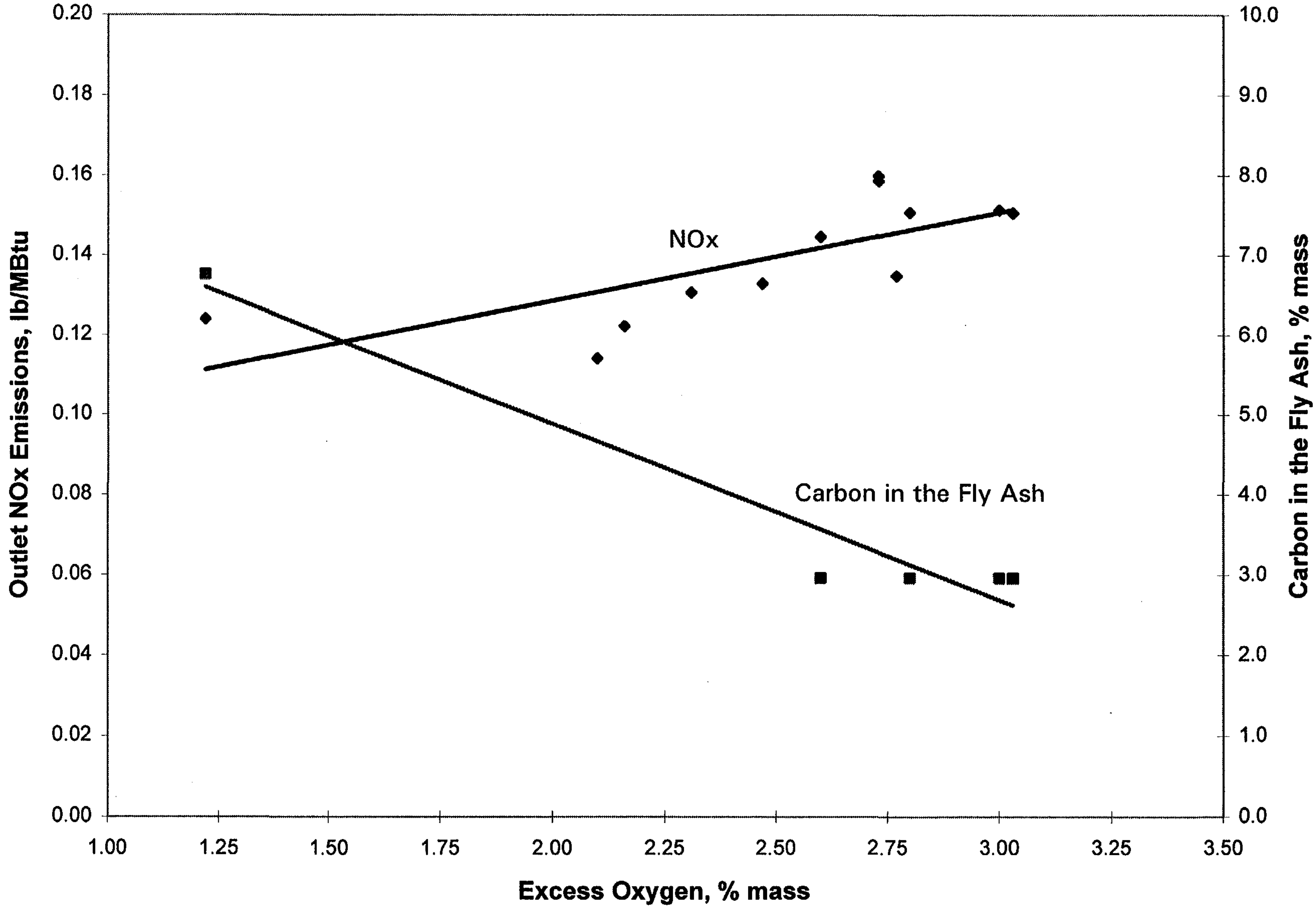



**Figure 11-10** NOx and Carbon in the Fly Ash versus Excess Oxygen: SOFA A and C (Viking Coal)

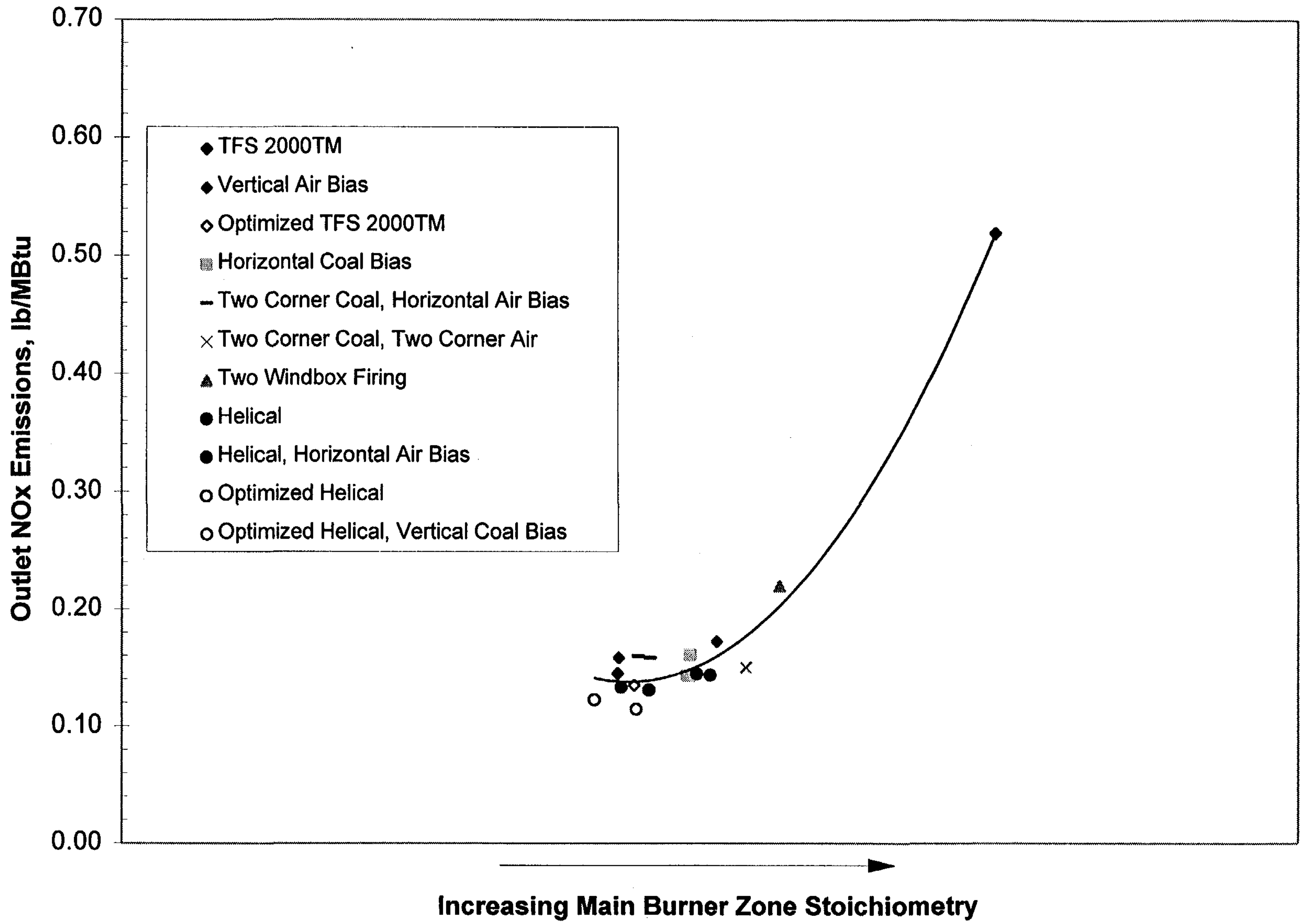



**Figure 11-11** Firing System Enhancements: SOFA A and C (Viking Coal)

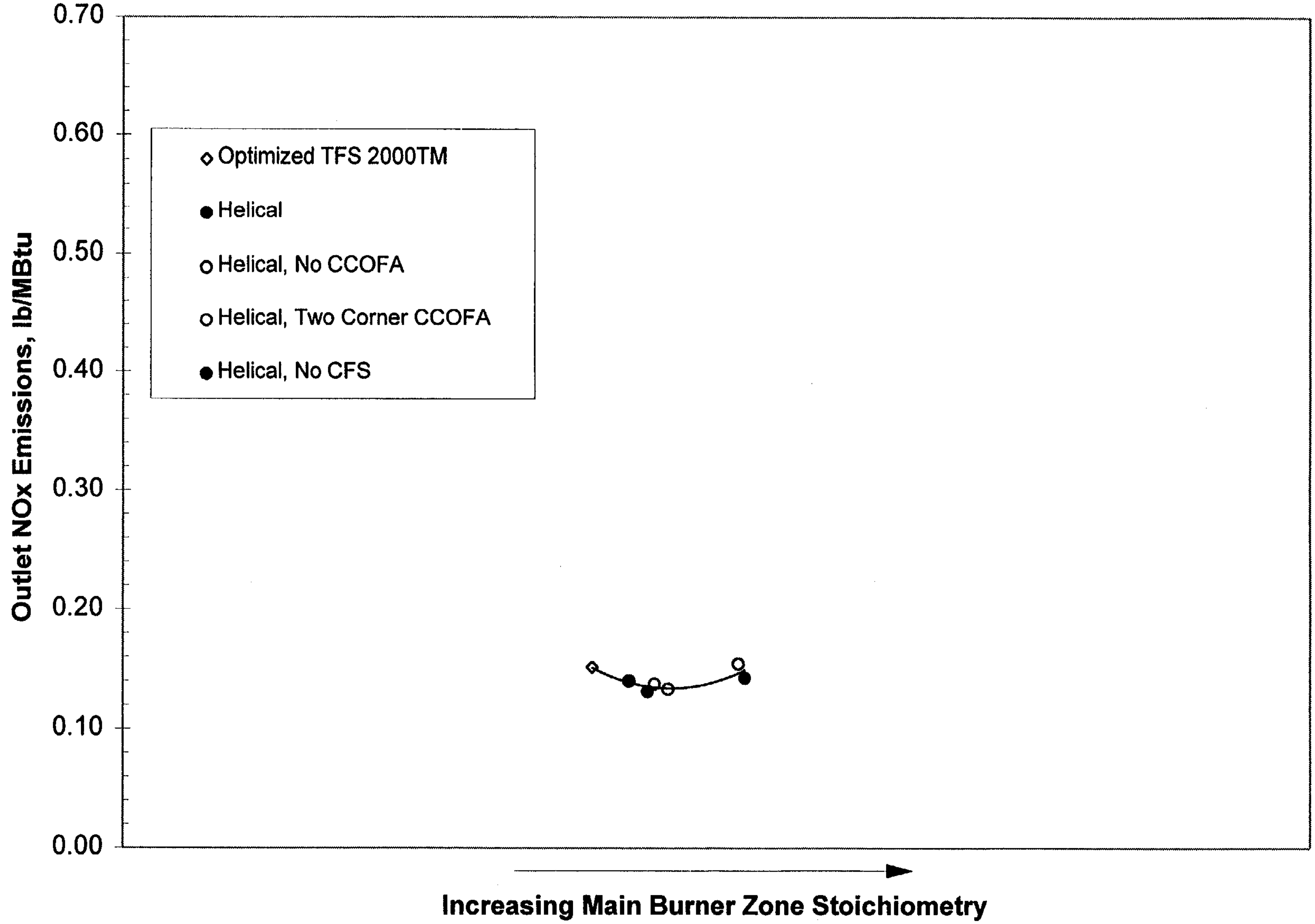



**Figure 11-12** Firing System Enhancements: SOFA A and C (Ashland Coal)

Table 11-7 BSF Combustion Test Program Matrix

| Configuration No. | CCOFA | SOFA A | SOFA B | SOFA C | Purpose for testing at configuration |
|---|---|---|---|---|---|
| 1 | X | X | - | X | TFS 2000™, helical arrangement |
| 2 | X | - | X | X | TFS 2000™ small boiler, helical |
| 3 | X | - | X | - | SOFA B res time effects, helical |
| 4 | X | - | - | X | SOFA C res time effects, enhancements |
| 5 | X | X | - | - | Effect of single SOFA A on residence time |
| 6 | X | - | - | - | Baseline characterization |

emissions measured in the BSF combustion test program were achieved while employing the nominal TFS 2000™ SOFA elevations A and C. A well-defined relationship between furnace outlet $NO_X$ emissions and bulk main burner zone (MBZ) stoichiometry exists (Figure 11-13). As stoichiometry decreases, $NO_X$ drops almost linearly from 0.5 lb/MBtu to 0.2 lb/MBtu, levels off as main burner zone stoichiometry is reduced further, reaches a minimum of 0.13 lb/MBtu $NO_X$ and increases slightly for further decreases in stoichiometry.

Clearly, $NO_X$ emissions remain very near the minimum value for a sizable range of bulk main burner zone stoichiometry. In this "optimum $NO_X$ stoichiometry range", $NO_X$ emissions vary by less than 0.02 lb/MBtu. The unburned carbon in the fly ash remains acceptable over the tested range of stoichiometries. In contrast to $NO_X$, carbon in fly ash varies inversely with bulk main burner stoichiometries, the maximum of 3 percent occurring at the lowest tested stoichiometry (Figure 11-14).

The results for the compressed SOFA elevations B & C show that furnace outlet $NO_X$ emissions are reduced from 0.55 lb/MBtu at the maximum stoichiometric ratio, to a minimum of 0.17 lb/MBtu, before increasing slightly with decreasing stoichiometry. Carbon in the fly ash levels remain below the 5 percent limit for the practical range of stoichiometries.

Overall, comparison between the results for the SOFA A & C and SOFA B & C furnace configurations reveals the effects of residence time on $NO_X$ emission and the relationship between $NO_X$ and bulk main burner zone stoichiometry. As the separated overfire air is moved upward in the furnace, from SOFA elevations B & C to elevations A & C, minimum $NO_X$ is decreased from 0.17 to 0.13 lb/MBtu. The slope of the stoichiometric ratio versus $NO_X$ curve for the compressed elevation configuration, SOFA B & C, is less steep than for SOFA elevations A & C. In addition, the main burner zone stoichiometry at which $NO_X$ is a minimum is increased.

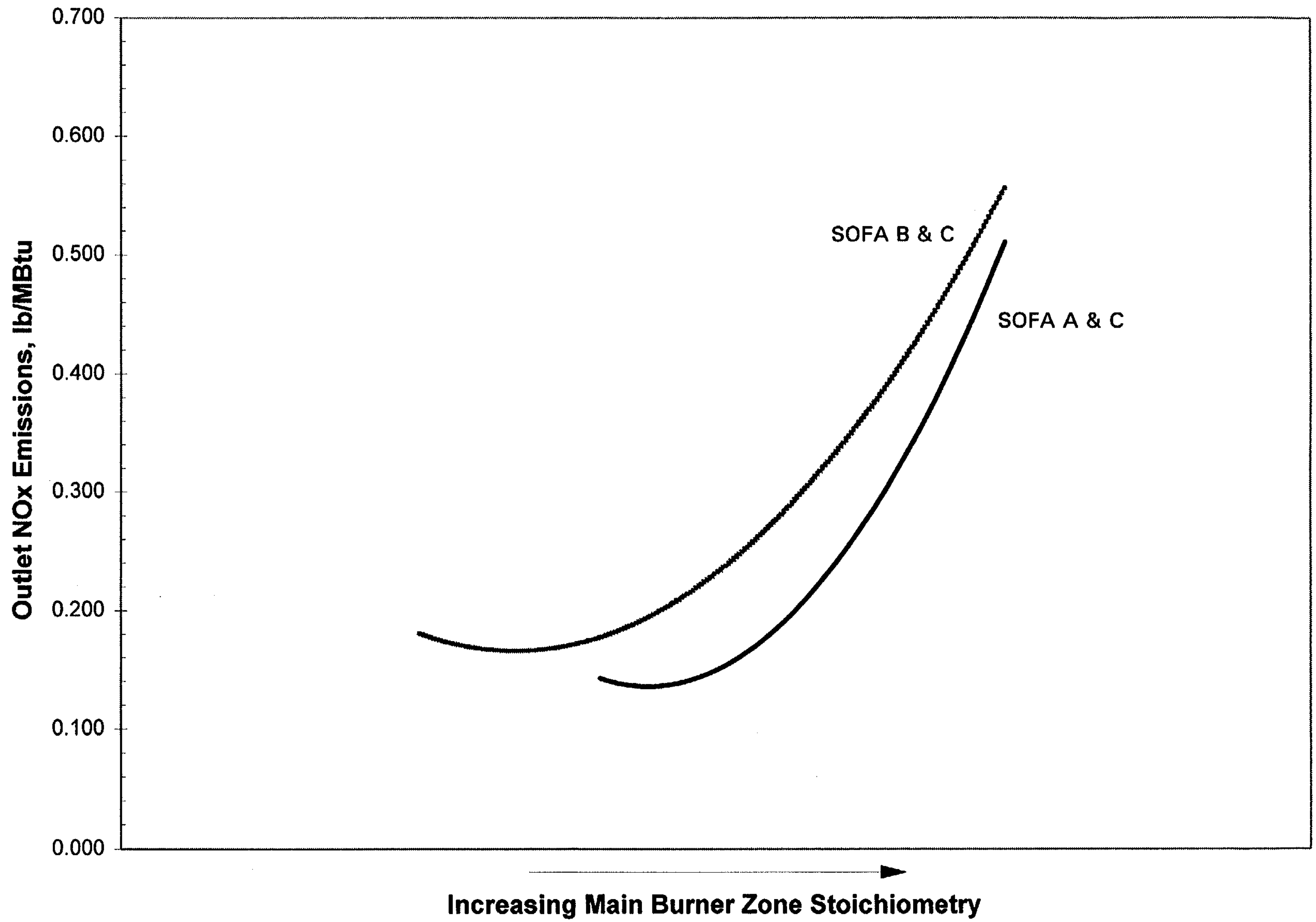



**Figure 11-13** Furnace Outlet NOx Emissions versus Stoichiometry - Multiple Elevations of SOFA: B and C, A and C (Viking Coal)

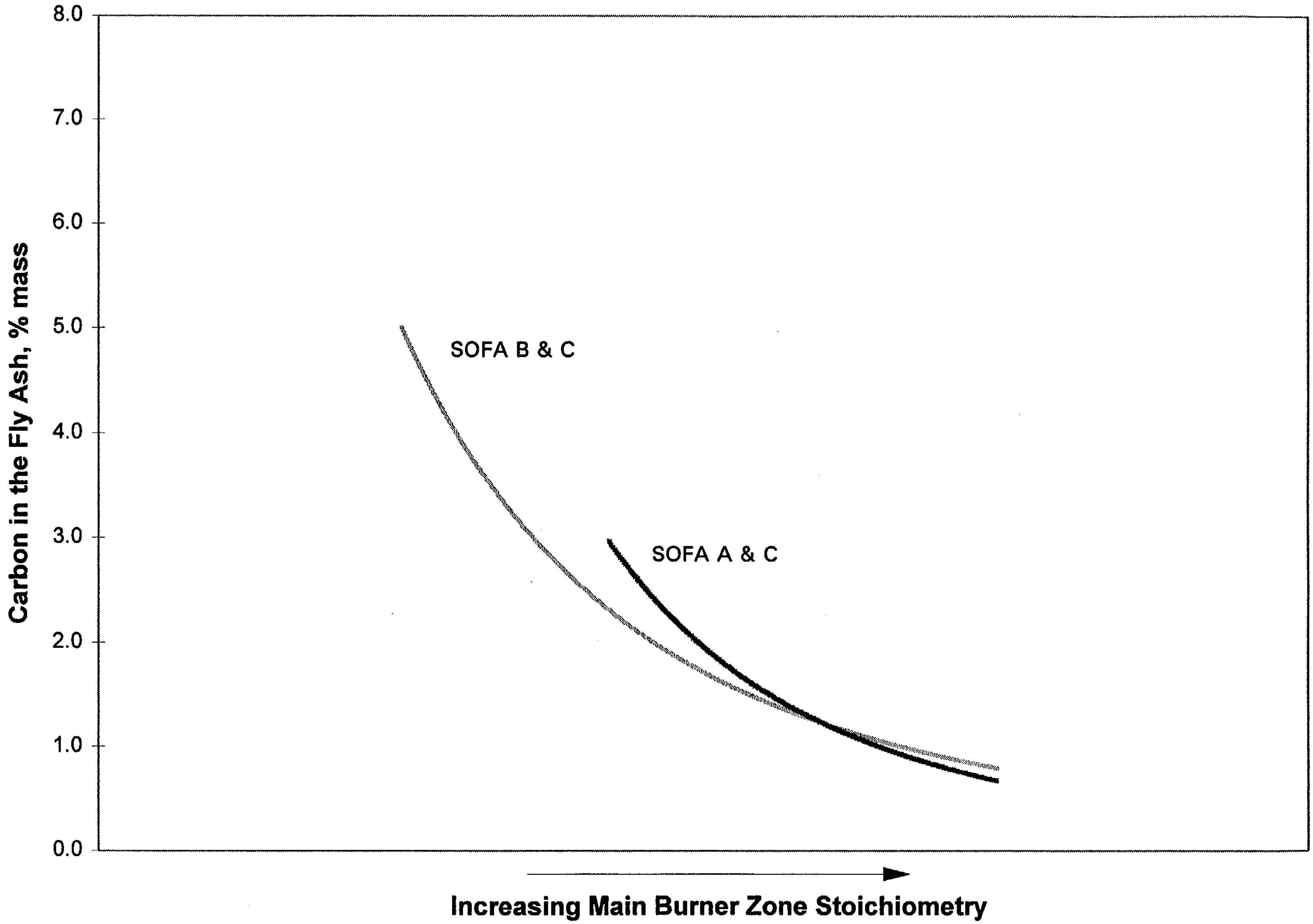



**Figure 11-14** Carbon in the Fly Ash versus Stoichiometry - Multiple Elevations of SOFA: B and C, A and C (Viking Coal)

Further combustion testing of firing system enhancements with the lower SOFA's B & C in-service, produced very similar results between firing systems within the minimum $NO_X$ stoichiometry range. None of the enhanced designs showed a significant improvement in furnace outlet $NO_X$ emissions over the standard, A & C SOFA configuration.

Tilting the SOFA A and C windboxes upward 20° increased the carbon in the fly ash from 3 to 4.6 percent, and altered the minimum $NO_X$ by 0.01 lb/MBtu as shown in Figure 11-15.

Carbon in the fly ash is also a function of staged residence time. The results indicate that for a given main burner zone stoichiometry, moving the overfire air downstream causes carbon in fly ash levels to increase.

In addition to the multiple SOFA configurations, comparisons were made to a single elevation of separated overfire air in service. Global staging residence time progressively increases as the overfire air is moved from the top of the windbox (at the close-coupled overfire air, CCOFA), to SOFA C, then SOFA B, until reaching the top elevation SOFA A. Figure 11-16 and Figure 11-17 show the $NO_X$ versus main burner stoichiometry relationship and corresponding carbon in ash respectively.

The close-coupled overfire air configuration provides the shortest global-staged residence time. Furnace outlet $NO_X$ emissions are at a maximum (0.5 lb/MBtu ) at the highest main burner zone stoichiometry. After reaching a minimum, 0.3 lb/MBtu, $NO_X$ increases only fractionally with further reduction in main burner zone stoichiometry.

Although the $NO_X$ value is significantly higher than that for any of the SOFA equipped configurations, the effect of global staging is still substantial. Carbon in the fly ash is not an issue, remaining less than 1 percent for all tested stoichiometries with CCOFA staging only.

Figure 11-16 shows furnace outlet $NO_X$ emissions as a function of main burner zone stoichiometry for lowest SOFA elevation C. The $NO_X$ emissions obtained for SOFA C are less than the CCOFA location, 0.2 versus 0.3 lb/MBtu, dropping as the global staging residence time increases. Under this SOFA C configuration, $NO_X$ emissions fell from 0.55 lb/MBtu to 0.20 lb/MBtu with decreasing stoichiometry. $NO_X$ increased as stoichiometry was lowered further, and an optimum stoichiometry range was observed. Tilting the SOFA windboxes upward (positive tilt) had the same effect as increasing the staged residence time (Figure 11-18). Tilting the SOFA nozzles 20° upward, further reduced the minimum $NO_X$ to 0.19 lb/MBtu.

Carbon in the fly ash is acceptable over the entire range tested, varying with stoichiometry as previously established and reaching a maximum of slightly higher than 3 percent, except for the tilted windbox tests which increased the carbon in ash to 3.8 percent.

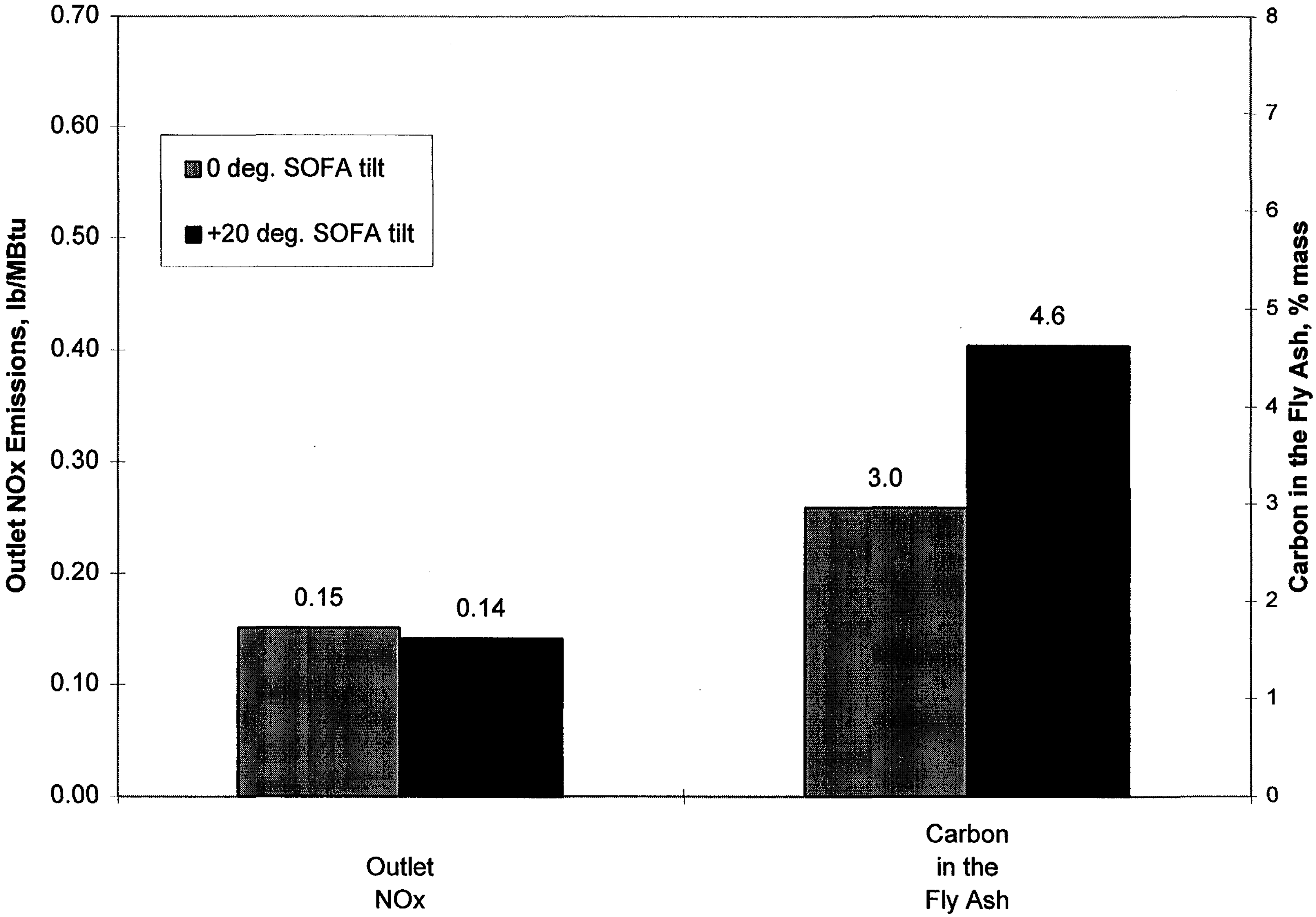



**Figure 11-15** Furnace Outlet NOx Emissions and Carbon in the Fly Ash versus SOFA Tilt: TFS 2000™ (Viking Coal)

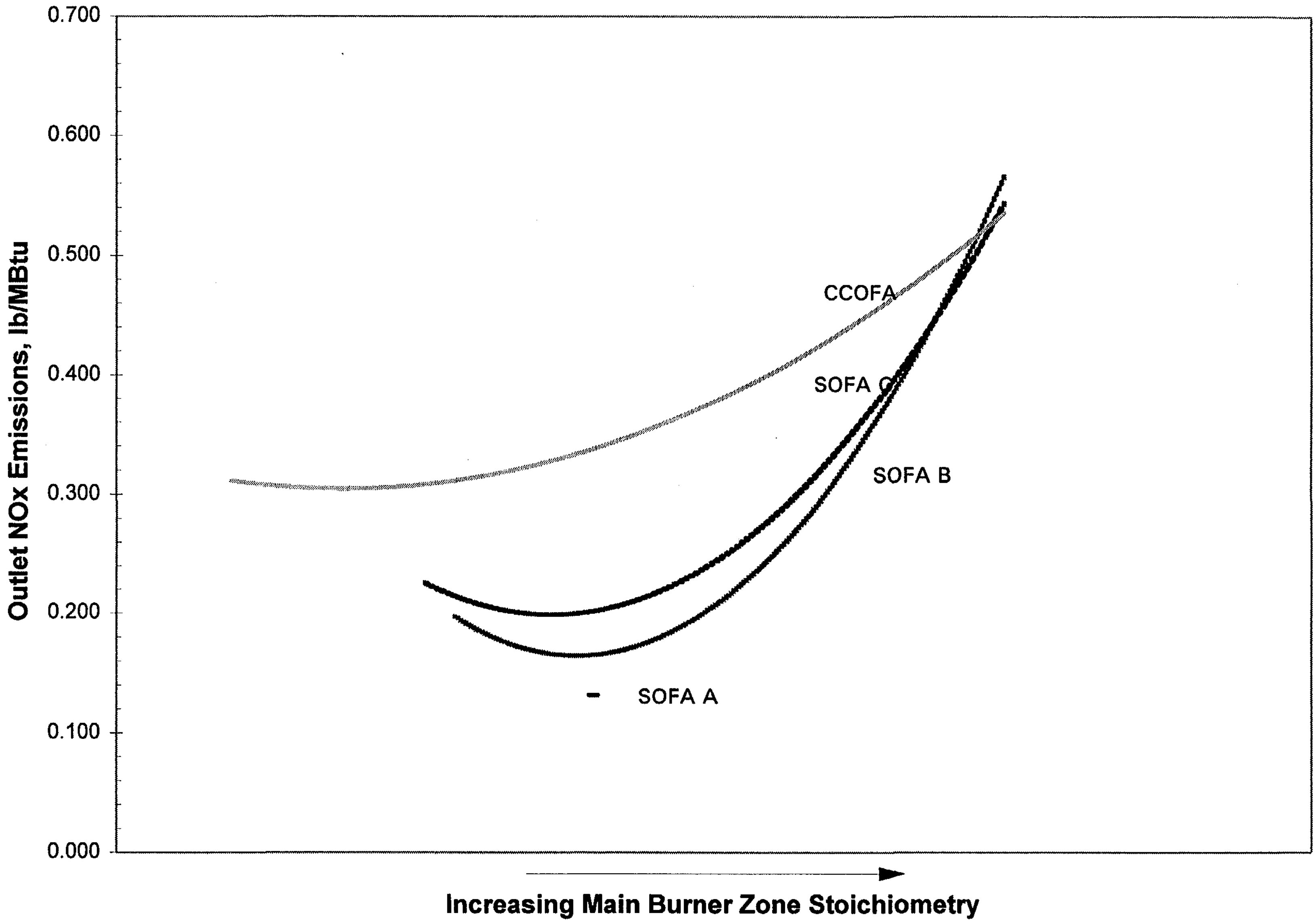



**Figure 11-16** Furnace Outlet NOx Emissions versus Stoichiometry - CCOFA, Single Elevations of SOFA: C, B, A (Viking Coal)

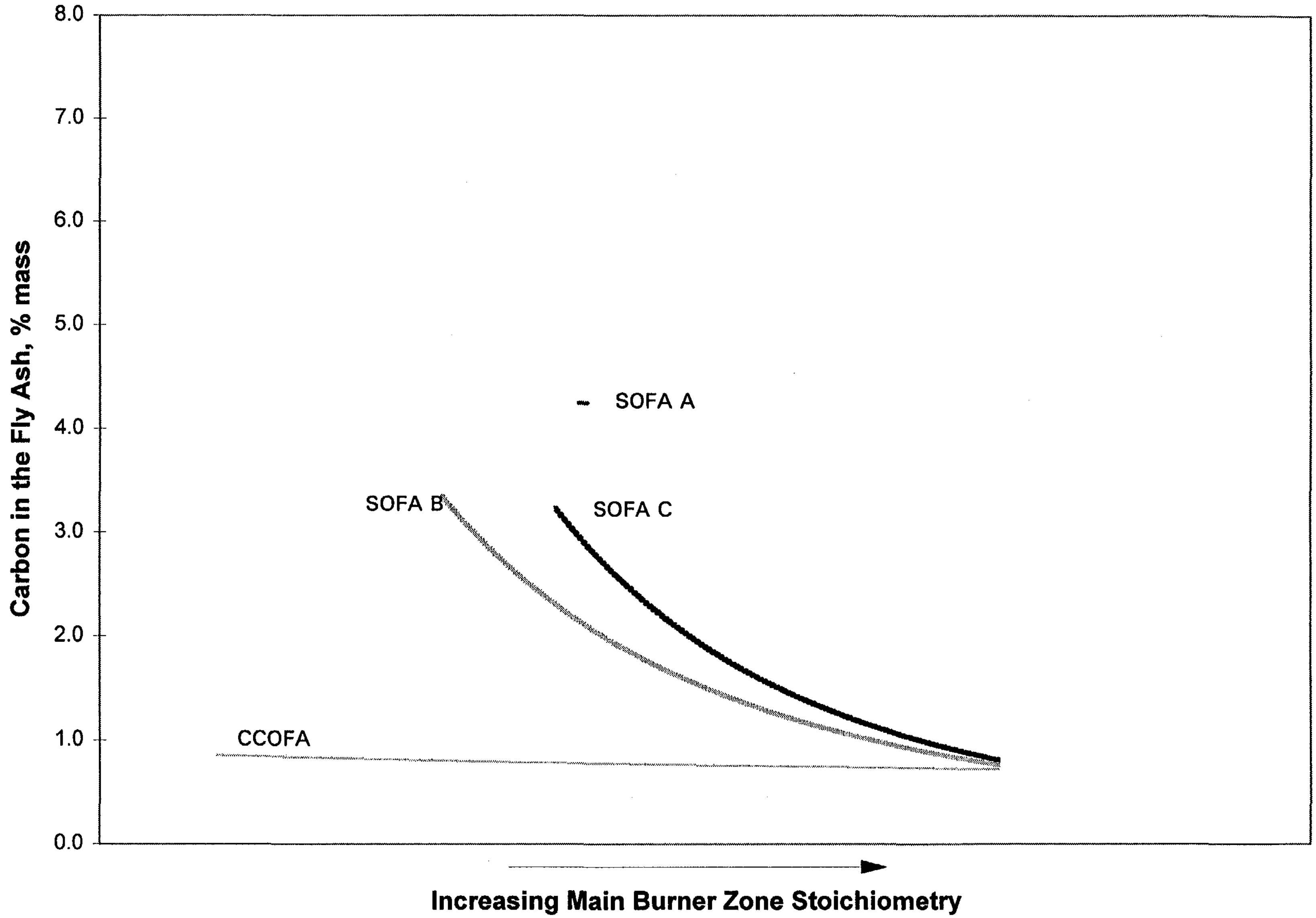



**Figure 11-17** Carbon in the Fly Ash versus Stoichiometry - CCOFA, Single Elevations of SOFA: C, B, A (Viking Coal)

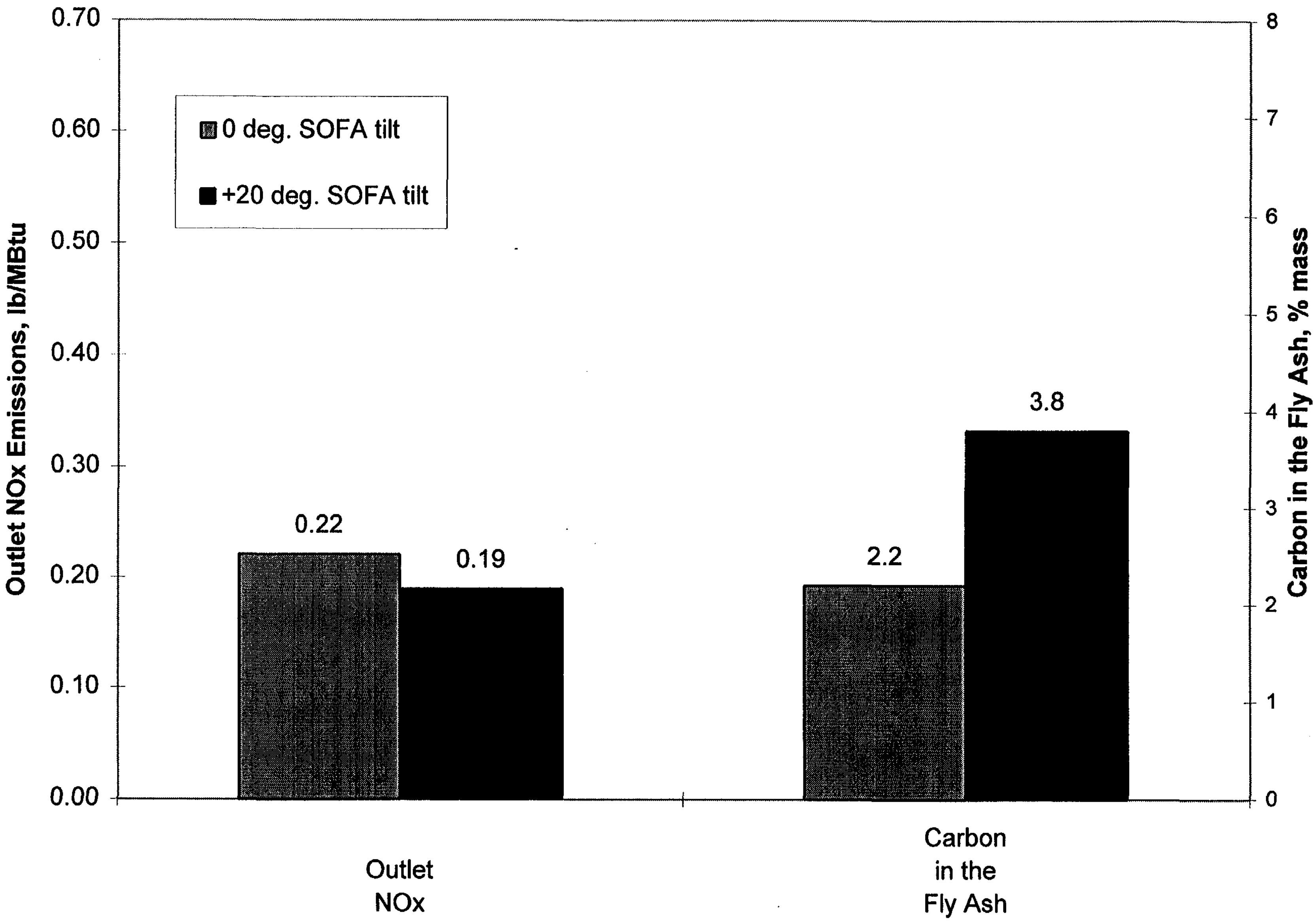



**Figure 11-18** Furnace Outlet NOx Emissions and Carbon in the Fly Ash versus SOFA Tilt: SOFA C (Viking Coal)

Differences in the performance of the firing system enhancements with the single SOFA C overfire air configuration, are small in comparison to the overall effect of global air staging. As shown in Table 11-8, furnace outlet $NO_X$ emissions vary from a low of 0.20 lb/MBtu for the optimized and coal-staged helical systems, to a high of 0.22 lb/MBtu for the standard tangential firing system. The observed difference of 0.02 lb/MBtu is consistent with that found for the TFS 2000™ firing system enhancements with the nominal SOFA A & C globally-staged configuration.

Table 11-8 Firing System Enhancement Testing: SOFA C

| Test # | Firing System Configuration | $NO_X$, lb/MBtu | $\Delta NO_X$, % |
|---|---|---|---|
| 3 | Standard | 0.22 | - |
| 110 | Standard | 0.22 | - |
| 127 | Helical | 0.21 | -5.1 |
| 127a | Low Set | 0.21 | -5.6 |
| 140 | Helical: Coal Staged | 0.20 | -10.6 |
| 117a | Two Corner Coal | 0.21 | -6.3 |
| 129 | Optimized Helical | 0.20 | -9.8 |
| 130 | Opt. Helical, Coal Staged | 0.21 | -6.6 |
| 131 | Standard, Two Corner CCOFA | 0.21 | -6.7 |
| 131a | 2 Corner Coal, 2 Corner CCOFA | 0.21 | -3.6 |

Next, the global staging residence time was increased by using SOFA elevation B. $NO_X$ emissions again fall sharply from 0.55 lb/MBtu to 0.2 lb/MBtu as the main burner zone stoichiometry decreases from the maximum value. Below this stoichiometry, $NO_X$ leveled off with respect to stoichiometry, achieving a minimum of 0.15 lb/MBtu. Subsequently, $NO_X$ increased as stoichiometry was decreased further, reaching 0.2 lb/MBtu at the lowest tested stoichiometry. Within a stoichiometry range of expected size and location, $NO_X$ emissions remain within 0.02 lb/MBtu of the minimum value. The overall shape of the curve is very similar to that obtained from the lower SOFA C and two-elevation SOFA testing. $NO_X$ values are slightly lower for the single SOFA case. Carbon in the fly ash remained low (approximately 3.5 percent) even at the lowest main burner zone stoichiometry.

Further combustion testing of firing system enhancements was conducted with SOFA B. None of the tested enhanced designs showed a significant improvement in furnace outlet $NO_X$ emissions over the standard firing system. Table 11-9 summarizes the performance for the SOFA B firing system enhancement configurations.

Table 11-9 Firing System Enhancement Testing: SOFA B

| Test # | Firing System Configuration | $NO_X$, lb/MBtu | $\Delta NO_X$, % |
|---|---|---|---|
| 107 | Standard | 0.15 | - |
| 134 | Helical | 0.15 | 0.4 |
| 200 | Helical, Vertical Coal Bias | 0.16 | +5.2 |

Finally, the effect of global staging at the maximum residence time was examined with only SOFA elevation A in service. Taken at a main burner zone stoichiometry shown previously to be in the optimum $NO_X$ range for this configuration, $NO_X$ emissions reached a low of 0.13 lb/MBtu. Carbon in the fly ash was 4.5 percent.

Like the multiple SOFA cases detailed above, staged residence time has a marked impact on $NO_X$ and carbon in the fly ash performance for the single SOFA and baseline furnace configurations. Figure 11-16 indicates that the main burner zone stoichiometry at which $NO_X$ is a minimum rises as the overfire air is moved upward in the furnace. In addition, the minimum $NO_X$ emissions are reduced by more than half with increased residence time, from 0.31 lb/MBtu for the CCOFA only arrangement to 0.13 lb/MBtu for the SOFA A configuration. In general, carbon in fly ash at a given bulk main burner zone stoichiometry increases as staged residence time is increased.

Comparison between the multi-SOFA and single SOFA configurations (Figure 11-19) reveals that for the Viking test coal, $NO_X$ performance is similar (0.01 lb/MBtu difference). From the measurements made during this test program, the second elevation of SOFA was not essential for the LEBS coals, as all furnace arrangements gave acceptable carbon in the fly ash performance for both the Ashland and Viking fuels. However, the two SOFA configuration is advantageous to provide flexibility when a broader variety of coals is considered, to achieve desired levels of carbon in the fly ash. The $NO_X$ emissions results for the tested furnace configurations appear in Table 11-10.

Table 11-10 BSF Combustion Test Program Results

| Configuration No. | CCOFA | SOFA A | SOFA B | SOFA C | Minimum $NO_X$ Emissions (lb/MBtu) |
|---|---|---|---|---|---|
| 1 | x | X | - | X | 0.13 |
| 2 | x | - | X | X | 0.17 |
| 3 | x | - | X | - | 0.16 |
| 4 | x | - | - | X | 0.20 |
| 5 | X | x | - | - | 0.13 |
| 6 | x | - | - | - | 0.31 |

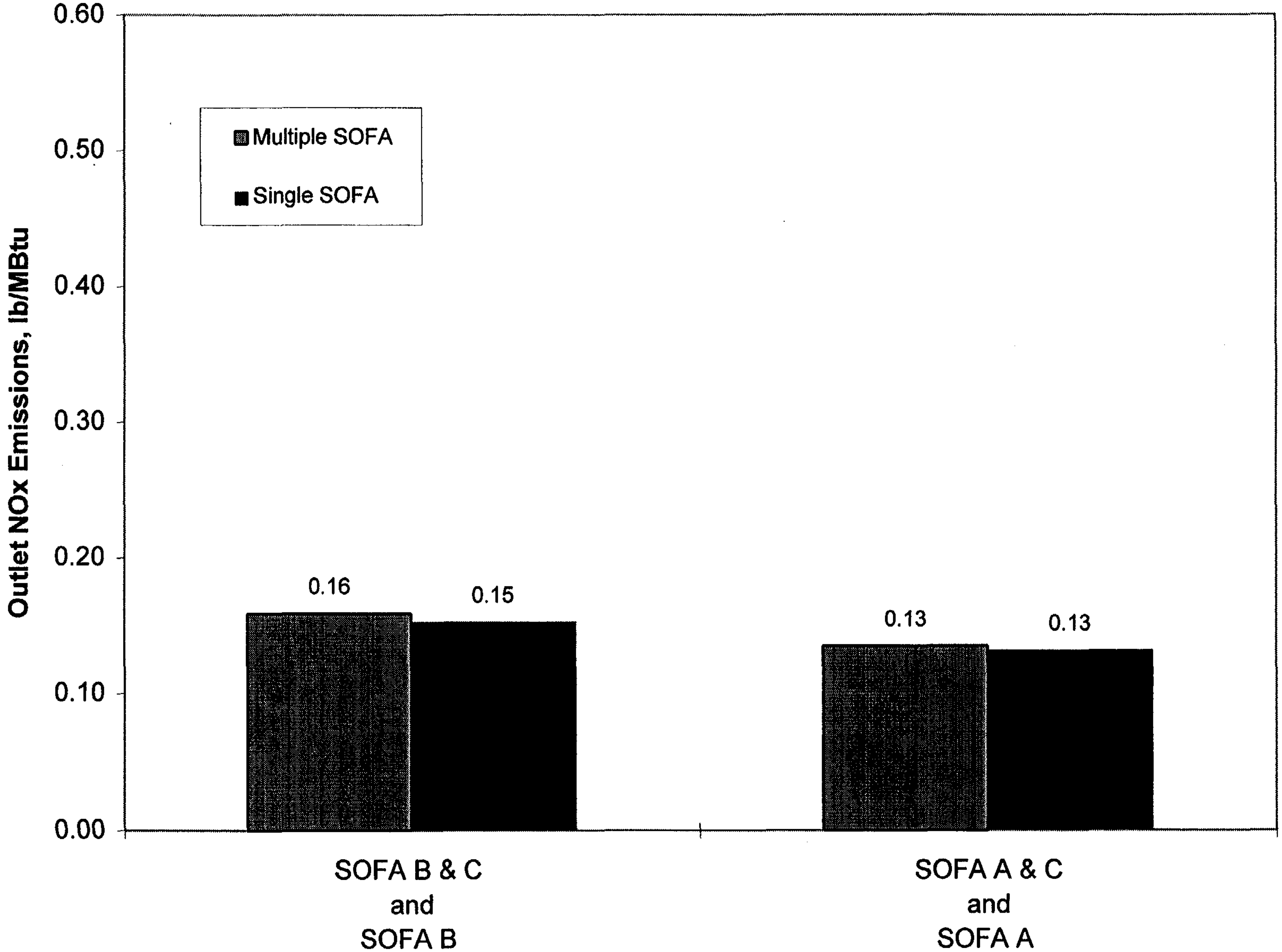



**Figure 11-19** Single SOFA versus Multiple SOFA Firing Systems: Furnace Outlet NOx Emissions (Viking Coal)

In summary, global stoichiometry history dominates the $NO_X$ emissions and carbon in the fly ash (CIFA) performance for all tested furnace configurations. $NO_X$ emissions dropped drastically as bulk main burner zone (MBZ) stoichiometry was reduced from the highest tested value, reached a minimum within a consistently observed optimum stoichiometry range and increased as stoichiometry was lowered beyond this point. Carbon in fly ash, however, was lowest at the maximum main burner zone stoichiometry and increased monotonically as stoichiometry was decreased.

Increasing staged residence time by moving the separated overfire air higher in the furnace reduced $NO_X$ emissions and caused the minimum $NO_X$ stoichiometry to increase. Carbon in fly ash performance was degraded as residence time increased.

$NO_X$ and carbon in fly ash were also shown to vary with excess oxygen. $NO_X$ emissions decreased and carbon in the fly ash increased as the level of excess oxygen was reduced. These contrary variances indicate that some optimization of stoichiometry history and excess oxygen may need to be made to obtain satisfactory $NO_X$ and carbon in fly ash performance. Although carbon in fly ash performance was acceptable for the single SOFA configurations tested here, firing systems with multiple levels of SOFA certainly offer more flexibility in performing this task.

Within the optimum $NO_X$ stoichiometry range, differences in $NO_X$ emissions between firing systems were small. While local stoichiometry control did have a small impact, global stoichiometry history was the prevalent force in the $NO_X$ formation and destruction process.

<u>Gas Side Temperature Imbalance</u>

Beyond $NO_X$ emissions and carbon loss characteristics, the best possible firing system for selection requires acceptable boiler thermal performance. Furnace outlet temperatures and total incident and absorbed heat fluxes were measured for current firing systems and those proposed for scale-up.

As is the case for $NO_X$ emissions, stoichiometry history has an effect on boiler thermal performance. Flame temperature is the predominant influence on heat flux. The peak adiabatic flame temperature occurs at a stoichiometry of one. Decreasing the amount of combustion air from stoichiometric levels results in incomplete combustion, while adding greater than the stoichiometric amounts of air results in thermal dilution and lowers flame temperatures. Hence, the highest incident heat flux is achieved for a stoichiometric mixture of fuel and air, and increasing or decreasing the stoichiometry from this value causes a reduction in heat flux. Differences between incident heat flux profiles were measured as a function of stoichiometry for the various firing systems. Heat flux profiles for the different firing systems, at their respective optimum stoichiometry, were compared.

The incident heat flux varies as a function of windbox stoichiometry history. Figures 11-20 and 11-21 show the vertical heat flux profile variation with bulk main burner zone (MBZ) stoichiometry for the standard and helical windbox arrangements, respectively. Both firing systems utilize the lowest elevation of separated overfire air, SOFA C, and therefore the shortest, global-staged residence time. Each figure also shows the incident heat flux without SOFA as a baseline comparison. The optimum stoichiometry is that which resulted in the lowest $NO_X$ emissions.

The standard firing system has the maximum variation in heat flux versus furnace elevation, for the optimum stoichiometry case, which is very similar to the linear, baseline (no SOFA) profile. Non-optimum stoichiometry conditions produce slightly more uniform heat flux profiles for the standard firing system, but shift the peak flux downstream of the main windbox. The helical firing system configuration has more uniform heat flux profiles for all stoichiometry cases as compared to the standard firing system. Again, the optimum stoichiometry is most similar to the baseline (no SOFA) profile, with the non-optimum cases shifting the peak flux closer to the SOFA C elevation.

Increasing the staged residence time, by using SOFA elevations B and C as compared to SOFA C, exacerbates the differences in the incident heat flux with main burner zone stoichiometry. For the standard configuration, Figure 11-22, the maximum deviation in heat flux occurs for the optimum stoichiometry case. As for the SOFA C configurations, the non-optimum stoichiometries show a shift in the peak heat flux beyond the main burner zone, in contrast to the optimum and baseline conditions.

Although not measured, an increase in the heat flux is expected downstream of SOFA B, as the remainder of the overfire air is added, (and the temperatures increase). Beyond SOFA B, the heat flux profile would be expected to flatten or increase, as the effect of the remaining combustion air is added. The baseline heat flux profile would continue to drop, as all combustion air was added earlier in the main burner zone. Under optimum conditions, the SOFA B and C standard firing system configuration may produce a more uniform heat flux profile than the baseline. For the helical firing system with SOFA B and C, only the optimum MBZ stoichiometry heat flux profile was measured. This profile is much less uniform than at SOFA C, although the complete effect of the SOFA location is not discernible due to the lack of measurements available beyond SOFA B. As seen in Figure 11-23, the peak heat flux profile is no longer in the main burner zone.

Finally, detailed heat flux testing was performed with SOFA B as the lone elevation of separated overfire air. Figure 11-24 shows the incident heat flux profiles for the standard windbox arrangement. The difference between heat flux profiles with MBZ stoichiometry has increased. The optimum stoichiometry profile is similar to the baseline profile, although lower in magnitude. Again, an increase or flattening of the optimum heat flux profile

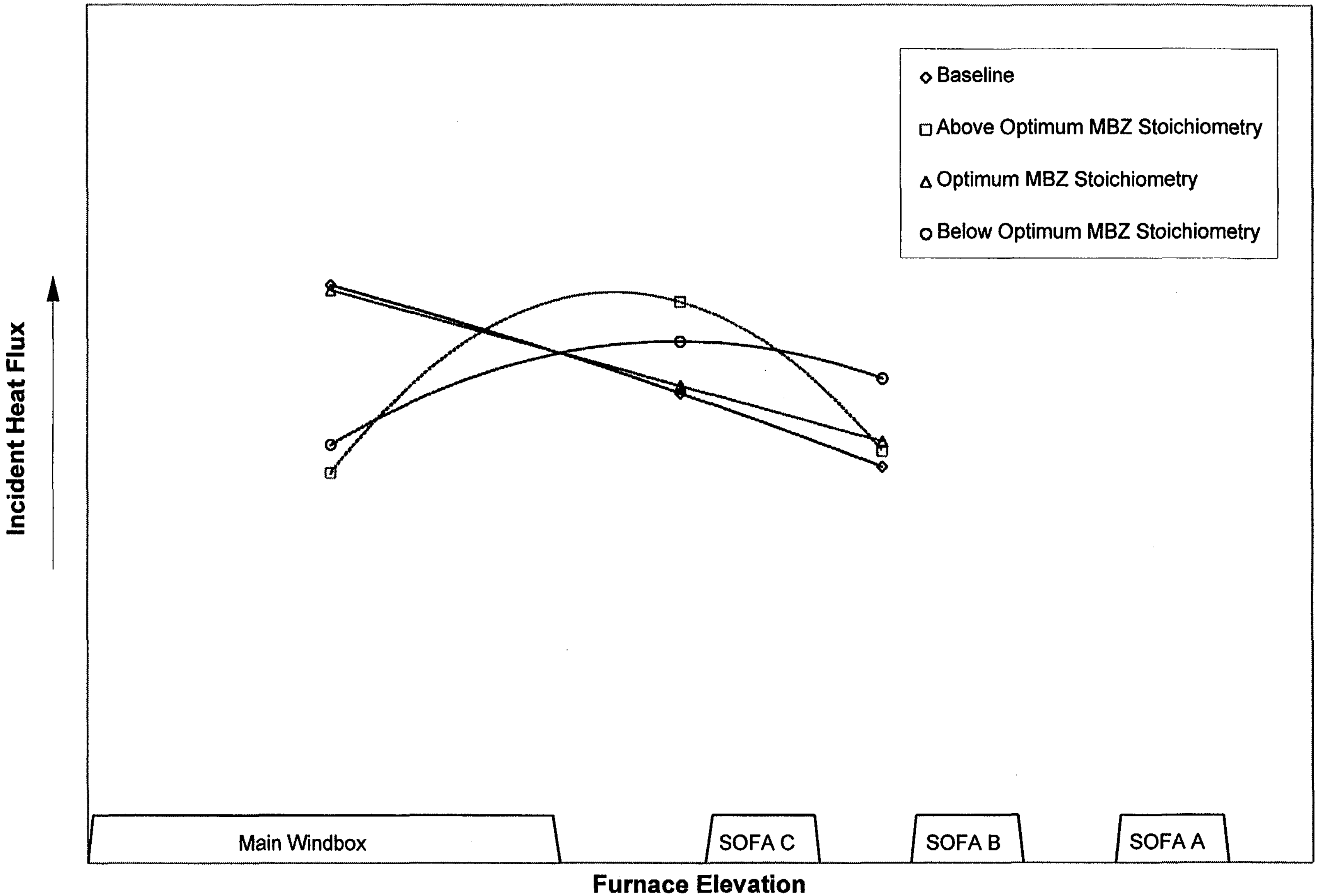



**Figure 11-20** Incident Heat Flux versus Furnace Elevation: Standard Firing System, SOFA C (Viking Coal)

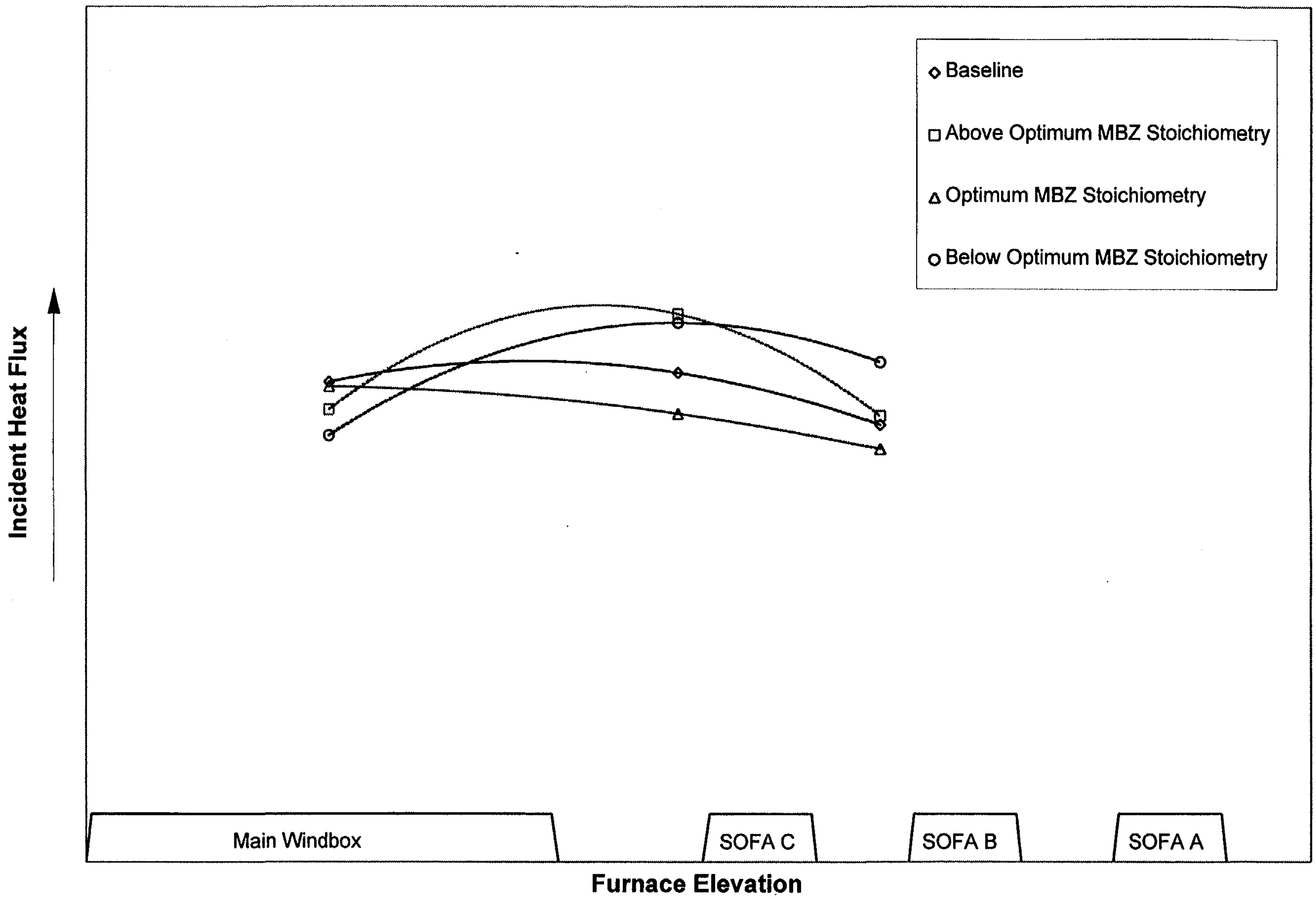



**Figure 11-21** Incident Heat Flux versus Furnace Elevation: Helical Firing System, SOFA C (Viking Coal)

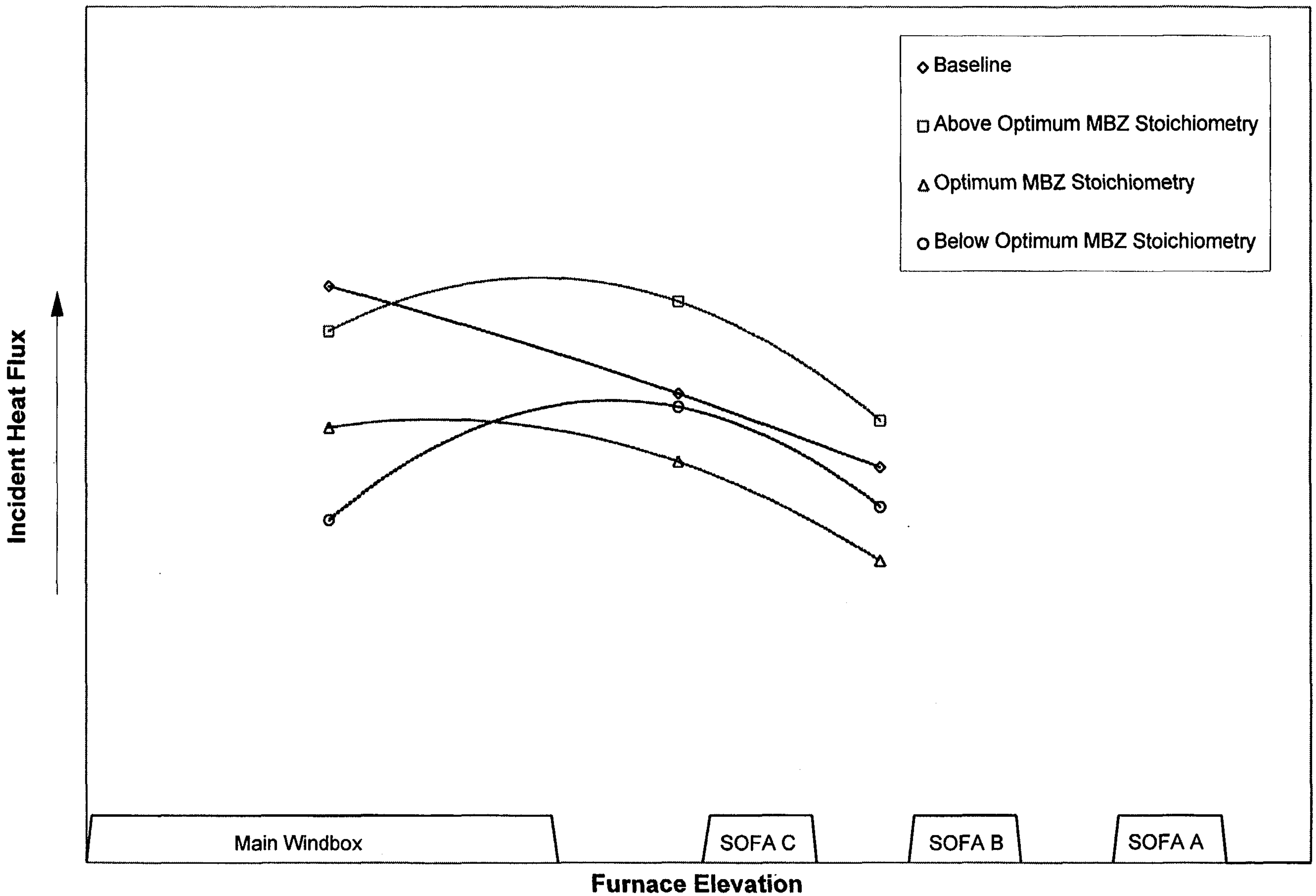



**Figure 11-22** Incident Heat Flux versus Furnace Elevation: Standard Firing System, SOFA B and C (Viking Coal)

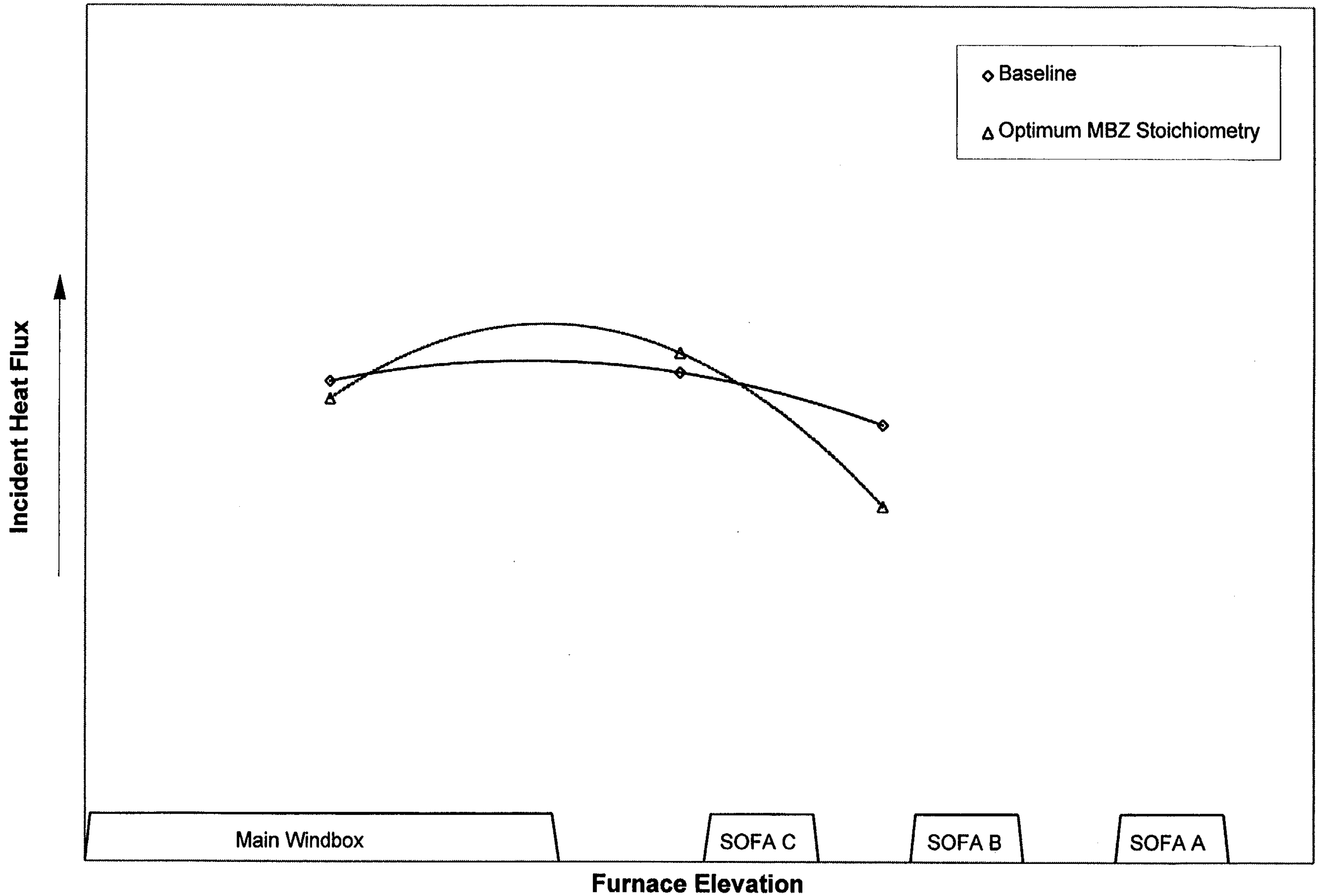



**Figure 11-23** Incident Heat Flux versus Furnace Elevation: Helical Firing System, SOFA B and C (Viking Coal)

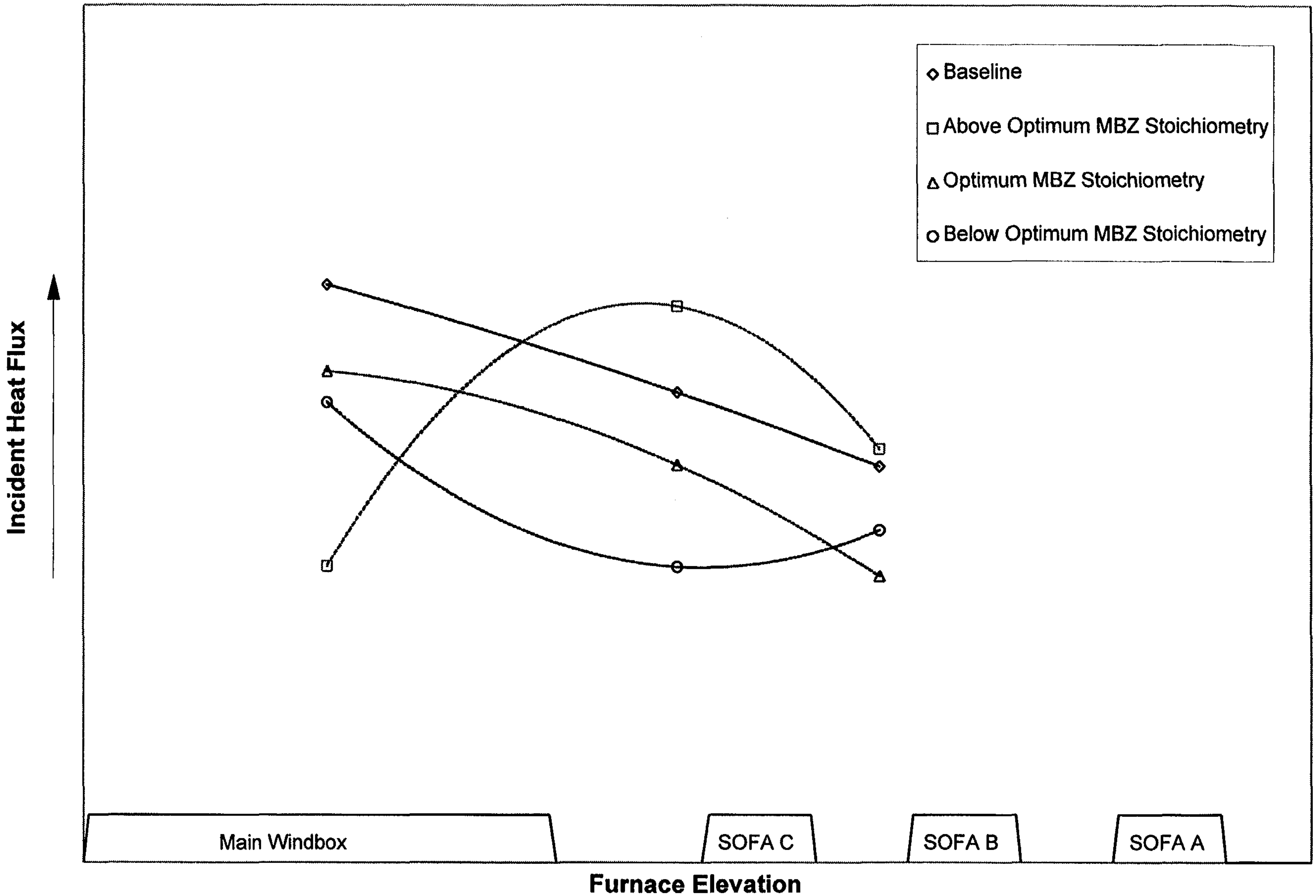



**Figure 11-24** Incident Heat Flux versus Furnace Elevation: Standard Firing System, SOFA B (Viking Coal)

with respect to the baseline case could be expected for increasing furnace elevation. As seen for the other SOFA configurations, the peak heat flux profile for the non-optimum (above) MBZ stoichiometry case is located above the main burner zone, and has the greatest deviation in heat flux. The below-optimum stoichiometry peak heat flux is within the main windbox and increases again after SOFA C, a different profile from all other tests.

For the helical with SOFA B configuration, the optimum MBZ stoichiometry heat flux profile (Figure 11-25) is less uniform compared to the no SOFA case and has a more linear profile. Again, one could anticipate the no SOFA and SOFA B curves crossing at some point downstream of SOFA B.

The furnace outlet gas temperature is a major indicator used in the comparison of thermal performance and design parameters. The effect of stoichiometry history is also evident in the furnace outlet temperatures for the various furnace configurations. Figure 11-26 shows that the overfire air location and firing system affect the temperature (HFOT) at the horizontal furnace outlet plane (HFOP). Staging combustion through the use of SOFA C lowers HFOT from the baseline values for both the standard and helical firing systems. The more deeply staged TFS 2000™ (SOFA's A and C) firing system decreases the temperature at the HFOP even further. However, the result for the helical SOFA B indicates that increasing staged residence time doesn't consistently lower the temperature at the HFOP. Rather, what is critical is where the overfire air is added.

Comparing the TFS 2000™ firing system and the baseline furnace configuration demonstrates why the location of the overfire air is so crucial. In the baseline arrangement, all the air required for complete combustion is introduced in the main windbox (MWB). Hence, the temperature of the bulk furnace gas will decrease as it rises due to the reduction in combustion. The TFS 2000™ firing system, however, uses upper and lower elevations of separated overfire air (SOFA A and C, respectively), to globally stage combustion. Because of its proximity to the furnace arch, the relatively cool air introduced at SOFA A reduces the temperature of the gas as it passes the HFOP. This air does in-turn sustain combustion, as evidenced by higher temperatures measured at the vertical furnace outlet plane (VFOP) for the TFS 2000™ firing system as compared to the baseline (no SOFA), firing system.

The stoichiometry history impacts the furnace outlet temperatures under a given global staging arrangement. The helical, coal-staged (Vertical Bias 2), and standard windbox arrangements have different horizontal furnace outlet temperatures. Without SOFA, the helical and standard firing systems are similar. With SOFA C, the HFOT for the standard firing system is higher than with the helical system. With SOFA B in service, the helical HFOT is higher still than the coal-staged (Vertical Bias 2), system. As shown for the incident heat flux profiles above, it is clear that the stoichiometry distribution within the main windbox affects the temperature at the HFOP.

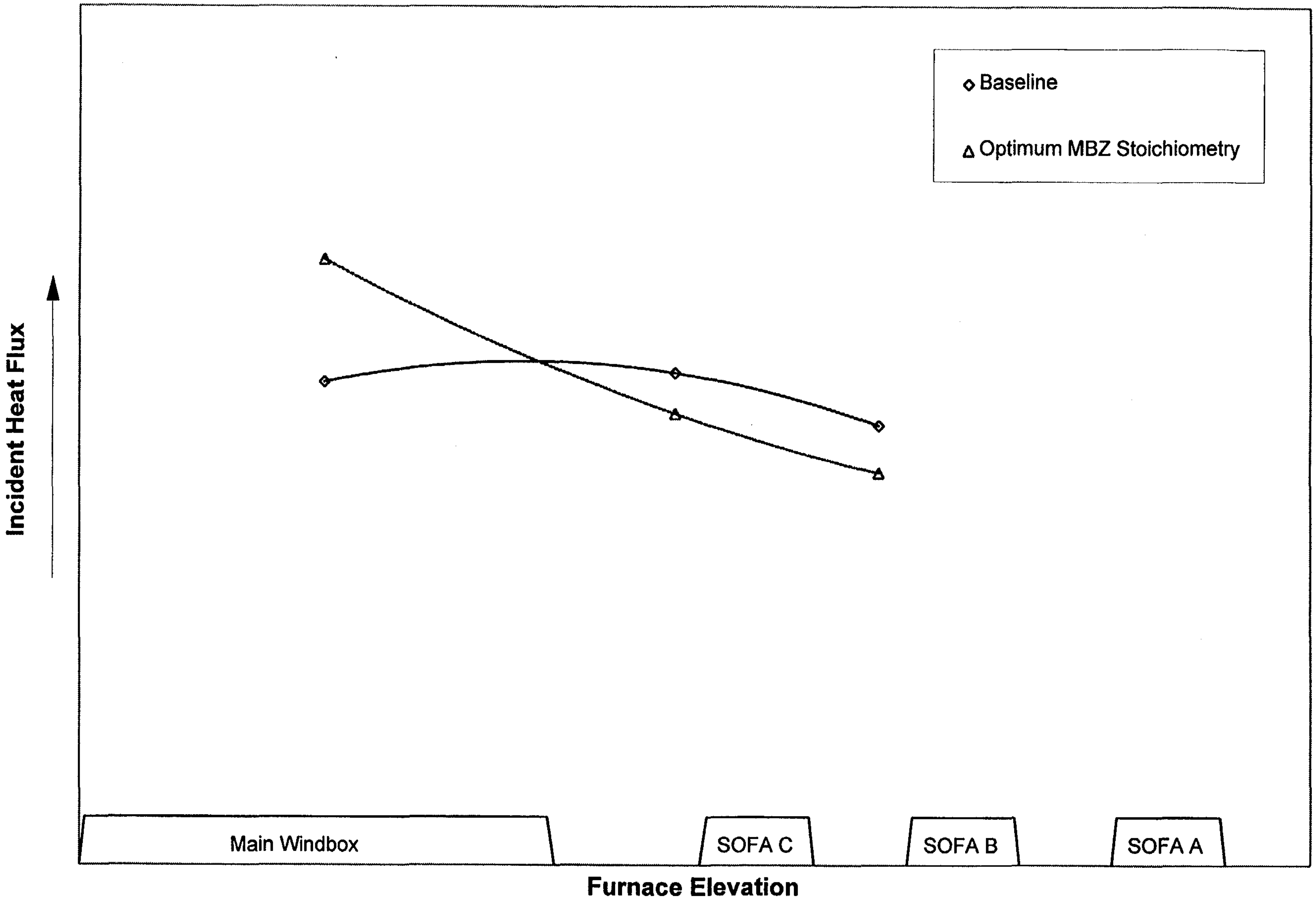



**Figure 11-25** Incident Heat Flux versus Furnace Elevation: Helical Firing System, SOFA B (Viking Coal)

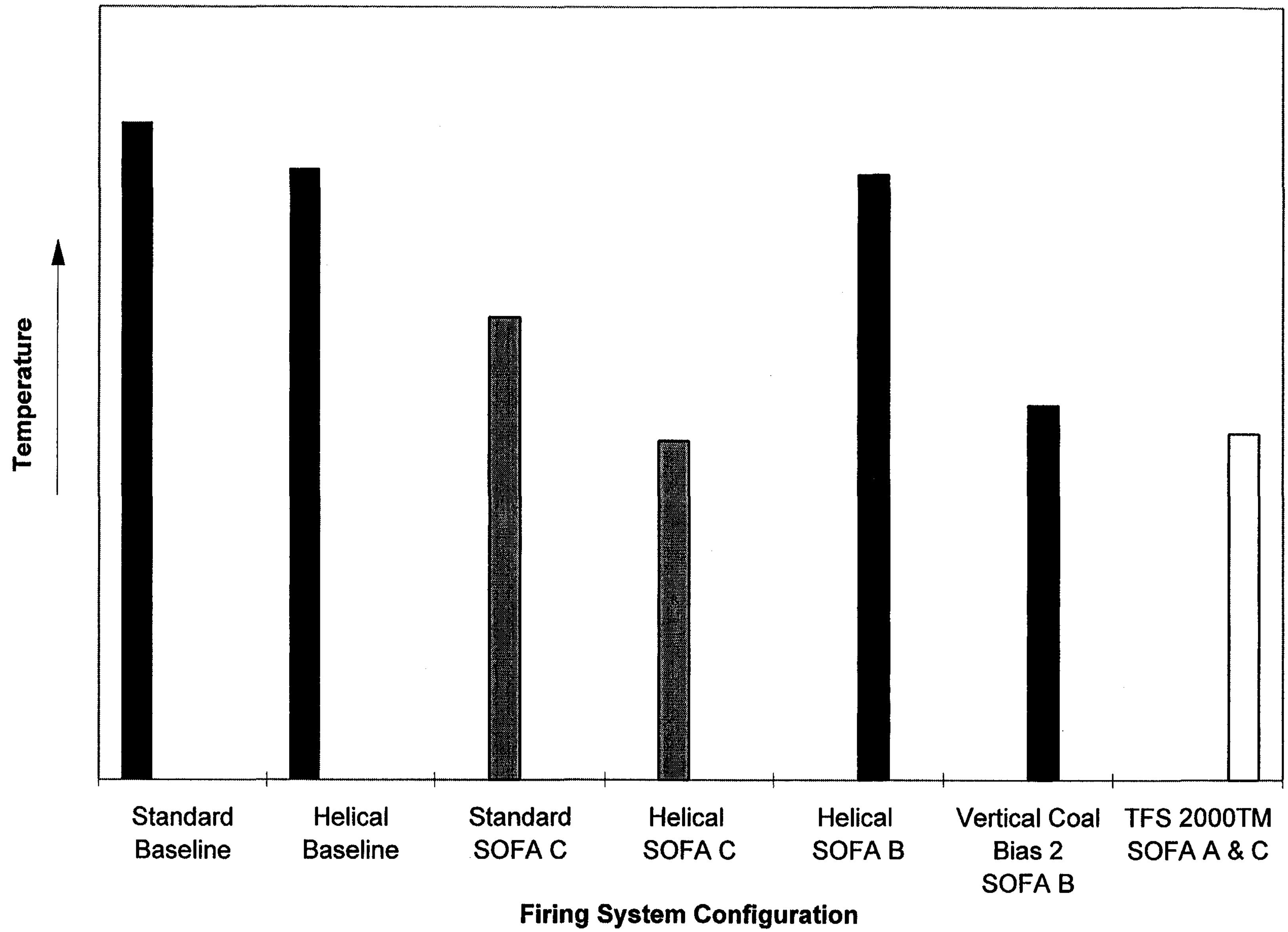



**Figure 11-26** Horizontal Furnace Outlet Plane Temperature versus Firing System (Viking Coal)

In summary, stoichiometry history has a significant effect on boiler thermal performance. At a variety of furnace configurations, the incident heat flux profile was observed to vary with the bulk main burner zone stoichiometry. In addition, the extent that the profiles varied with MBZ stoichiometry increased as staged residence time increased. Comparison between the helical and standard main windbox arrangements showed local stoichiometry to impact the incident heat flux profiles as well. Also, furnace outlet temperature (HFOT) was shown to be influenced by the stoichiometry history. Overfire air location was observed to have the major effect on HFOT. Again, local stoichiometry affected this aspect of thermal performance, with the helical, coal-staged (Vertical Bias 2) and standard firing systems giving different HFOTs for identical furnace overfire air configurations. Finally, SOFA tilt impacted HFOT, with the level of effectiveness increasing as the separated overfire air was moved upward in the furnace.

## Pulverizer Development

*Background*: As $NO_X$ levels are pushed lower, it becomes more important that fuel particle size distribution be more tightly specified as a means of controlling combustible losses. This is because combustion conditions which are favorable for achieving low $NO_X$ tend to run counter to those that are favorable for good coal combustion. Controlling the proper coal particle size distribution has obvious effects on facilitating better carbon burnout and perhaps even enhancing $NO_X$ reduction through earlier release of nitrogen species in the near-burner zone, where the opportunity for conversion to molecular nitrogen is increased.

Work was performed in the Pulverizer Development Facility (PDF) to determine and characterize the coal fineness which is obtainable from the current state-of-the-art pulverizers and to evaluate various Dynamic™ classifier designs. This information includes the effects of changing size distribution requirements on pulverizer performance in terms of power requirements and capacity.

Results from this task were integrated with subsystem design to select fuel size distribution for testing of the firing system in Task 11.

*Testing*: The plan was to evaluate various Dynamic™ classifier designs and to provide guidelines for a design which provides the optimal combination of large particle removal (top-size control) and maximum fineness (production of minus 200 mesh particles). The evaluation would include computational fluid Dynamic™ modeling, stand alone testing of classifier designs, as well as testing of classifier designs in the PDF pulverizer. In addition, it is possible to alter the design of the grinding rolls themselves, and it is known that grinding roll design can influence pulverizer performance. Thus, an additional aspect of the testing was to evaluate the effect of grinding roll design. In all testing, the influence of these advanced pulverizer components on fuel fineness, power requirements, and various other aspects of pulverizer performance were recorded for evaluation.

Test matrices are given in Tables 11-11 and 11-12.

Table 11-11 PDF Static Classifier Test Matrix

| Coal Rates Tested (lb/hr) | Air Flow Rates Tested (lb/hr) | Classifier Settings |
|---|---|---|
| 6,500 | 9,000 | Various |
| 5,500 | 9,000 | Various |
| 4,900 | 9,000 | Various |
| 4,000 | 8,000 | Various |
| 2,600 | 9,000 | Various |
| 2,600 | 7,200 | Various |
| 1,300 | 6,300 | Various |

Table 11-12 PDF Dynamic™ Classifier Test Matrix

| Classifier Designation | Rotational Speeds Tested (rpm) | Coal Rates Tested (lb/hr) | Air Flow Rates Tested (lb/hr) | Grinding Roll Designs Tested |
|---|---|---|---|---|
| HP1 | Various | Various | Various | 2 |
| HP2 | Various | 6,500 | 9,000 | 1 |
| RB1 | Various | 6,500 | 9,000 | 2 |
| RB2 | Various | 6,500 | 9,000 | 1 |

The PDF and Classifier Test Facility (CTF), located at ABB's Power Plant Laboratories, were the sites of all testing and are described as follows.

The heart of the PDF is a HP 323 Pulverizer; a 3-journal 32 inch bowl commercial mill. Its design as well as its location allows for easy interchanging of various mill components (e.g. Dynamic™ classifiers or grinding rolls). Mill performance results from the PDF are readily scaleable to industrial and utility size pulverizers.

All material flows to the HP323 mill are automatically controlled . A Thayer gravimetric coal feeder (max. capacity of 10,000 lb/hr) is used to feed crushed coal (nominal 2 in x 0) to the mill. Crushed coal is supplied to the coal feeder from a 10 ton crushed coal silo. Coal is supplied to the feed silo using a combination of typical coal handling equipment (screw conveyors, bucket elevator, etc.) which has a maximum capacity of 6 tons per hour.

Hot air (250 to 500 °F) is supplied to the mill using a 200 HP Lamson blower (max. capacity of 5,000 SCFM). The air is heated using a 3.5 MBtu/hr indirect fired air heater. Both air flow rate and temperature are automatically controlled so as to maintain the mill at constant operating conditions.

Pulverized coal product exits the classifier section of the mill through four fuel pipes and is pneumatically conveyed to a collection cyclone where the solids are separated from the air. The cyclone discharges the product into a 20 ton storage silo from where it was pneumatically conveyed to the product silos at the BSF. The air from the cyclone is discharged to a baghouse where any remaining coal dust is removed prior to discharging to the atmosphere.

All mill operating parameters are controlled using a programmable computer based control system. Mill operating conditions, such as mill inlet/outlet temperatures, mill differential pressures, mill power consumption, etc., are continually monitored and recorded using a computer based data acquisition system. In total there are over 48 different data which are recorded and then stored in a format that is readily imported into an Excel spreadsheet for later data analysis.

Typical performance testing on the PDF is done by performing a classifier "sweep". A classifier sweep consists of incrementally closing the classifier inlet vanes (in the case of the static classifiers) or incrementally increasing the speed of the classifier (in the case of the Dynamic™ classifier). At each classifier setting mill performance data is recorded and a mill product sample is aspirated from the fuel lines using a cyclone collector for particle size analysis.

The CTF was designed to characterize key operating parameters of ABB's Dynamic™ and static classifier products. In the CTF classifier performance is determined by measuring the flow rates and size distributions of the particles passing through the classifier as "product" and those being rejected by the classifier. The central part of the CTF is the classifier test section. This consists of a 24 inch cylinder where the classifier is located. The speed of the classifier is controlled using a variable frequency motor speed controller and its speed is measured using a tachometer. The top of the classifier test section is removable so that different classifier designs can be tested.

A 60 Hp mill exhauster fan is used to provide conveying air (5,000 SCFM max.) to the classifier inlet. Unclassified solids (feed) are metered as they are passed through a variable speed rotary air lock into a mixing tee located upstream of the fan inlet. Air plus feed enter through the bottom of the classifier and are distributed as they are passed through an annulus formed between the outside cylinder and the rejects cone and are then swept up to the classifier for separation. The air flow rate is measured using a venturi downstream of the fan inlet.

Fine particles that pass through the classifier as product leave the test section via an exit manifold and are directed to a product collection cyclone which separates the coal particles from the air. The solid discharge of the cyclone is equipped with a rotary airlock and a diverter valve. The diverter valve controls the direction of the product stream to either the solids holding tank or to the product sampling point. Clean air from the cyclone is returned to the solid/air mixing tee.

The coarse particles rejected by the classifier are collected by the reject cone and flow by gravity into a rotary airlock and diverter valve. The diverter valve controls the direction of the stream to either the solids holding tank or to the reject sampling point. The two diverter valves for the product and reject streams are pneumatically controlled and are operated simultaneously so that both the product and reject samples can be taken at the same time.

As with the pulverizer testing, classifier performance testing is performed by incrementally increasing the speed of a Dynamic™ classifier or changing the vane setting of a static classifier and simultaneously collecting the product and reject samples. The size distributions of these samples are then determined by using both sieve and sub-sieve analytical methods.

*Results and Analysis*: The data collected during stand alone classifier testing included the mass rates and particle size distributions of the fine product and coarse product streams, in addition to air flow rate and classifier pressure drop. In this way it was possible to construct a complete material balance for each test and, thus, determine classifier efficiency as a function of classifier design and operating speed.

The PDF mill data were first reviewed to determine the influence of (1) classifier type (static versus Dynamic™ classifier) on size distributions produced, (2) throughput and product size produced on mill power requirements for both static and Dynamic™ classifiers, and (3) air flow on mill performance.
With respect to size distributions produced, it was found that for size distributions having the same weight percent passing 200 mesh (74 microns):

- Dynamic™ classifiers remove large particles more efficiently, that is, their products have smaller percentages of +50 and +100 mesh particles (297 and 149 microns, respectively) for the same weight percent passing 200 mesh. This is illustrated in Figure 11-27.
- Size distributions from the mill, when equipped with the various Dynamic™ classifiers were quite similar.

Figure 11-27 also shows a maximum of approximately 84 percent passing 200 mesh for the static classifier equipped mill. It was possible to produce finer products but only at lower throughputs (the data in the figure were for a throughput rate of 6,500 lb/hr). The data for the Dynamic™ classifier were obtained at the same throughput

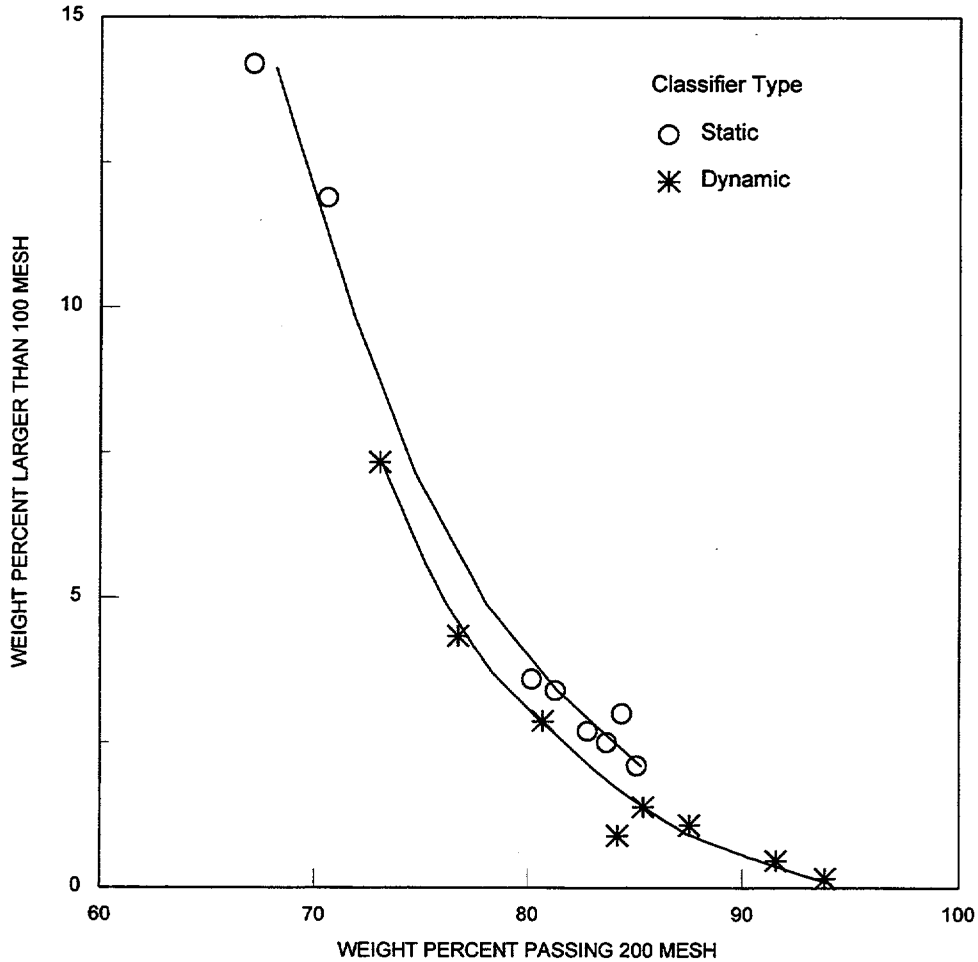



Figure 11-27 Comparison of Size Distribution Data Static versus Dynamic™ Classifiers

rate of 6,500 lb/hr and, as seen, a significantly finer product was achieved. This phenomenon has been observed in the field and clearly demonstrates a benefit of the Dynamic™ classifier.

The relationship between mill power, throughput and product size were next reviewed, first for the Dynamic™ classifier designs and then for comparison to the static classifier. Figure 11-28 plots mill power versus weight percent passing 200 mesh for the HP1 classifier design, for tests conducted at an air flow rate of 9,000 lb/hr. As expected, higher throughputs require more power. Unlike mills with static classifiers, however, product fineness does not significantly degrade with increased throughput. Figure 11-29 compares the same data on the basis of specific energy (kw-hr/ton). Within reasonable ranges of air and coal flows, specific energy at a given product size should be approximately constant and independent of throughput. This is seen to be true for the two higher throughputs but less so for the lowest. This means that at a given specific energy, mill throughput will generally be limited by the power available to drive the unit, with maximum throughput (ton/hr) being estimated by maximum available power divided by specific energy. Data from the HP1 classifier were then compared to results from the other classifier designs, see Figure 11-30. As shown in this figure, classifier design can influence total mill power requirements. Finally, data for the Dynamic™ classifiers can be compared to data for the static classifier. This is done by inspection of Figures 11-31 and 11-32. As seen, up to about 80 weight percent passing 200 mesh a static classifier can provide specific energy performance equivalent to a Dynamic™ classifier but is clearly not as suitable for finer grinding.

The influence of air flow rate was next reviewed. Although reduced air flow rate can improve boiler performance there are lower limits which are dictated by coal drying requirements and conveying requirements. The minimum air flow for drying is dependent upon a number of factors, including the mill inlet and outlet temperatures, and the feed and desired product moisture contents. Mill inlet and outlet temperatures are typically set at levels which will not damage mill components and, given these, total air flow for drying is dictated by the amount of moisture which must be evaporated. Conveying requirements are also dictated by two factors: air velocities exiting the mill must be sufficient to convey product away from the unit, and air velocities within the pulverizer must be sufficient to convey particles to the classifier. In the first case, sufficient conveying velocities can be achieved by appropriate sizing of the fuel pipes exiting the mill. However, if there is insufficient air velocity through the mill body itself, a high internal circulating load can build up which can limit throughput (recycling material will displace fresh feed grinding capacity) and cause the mill to draw more power. Limited testing was conducted to confirm this phenomenon.

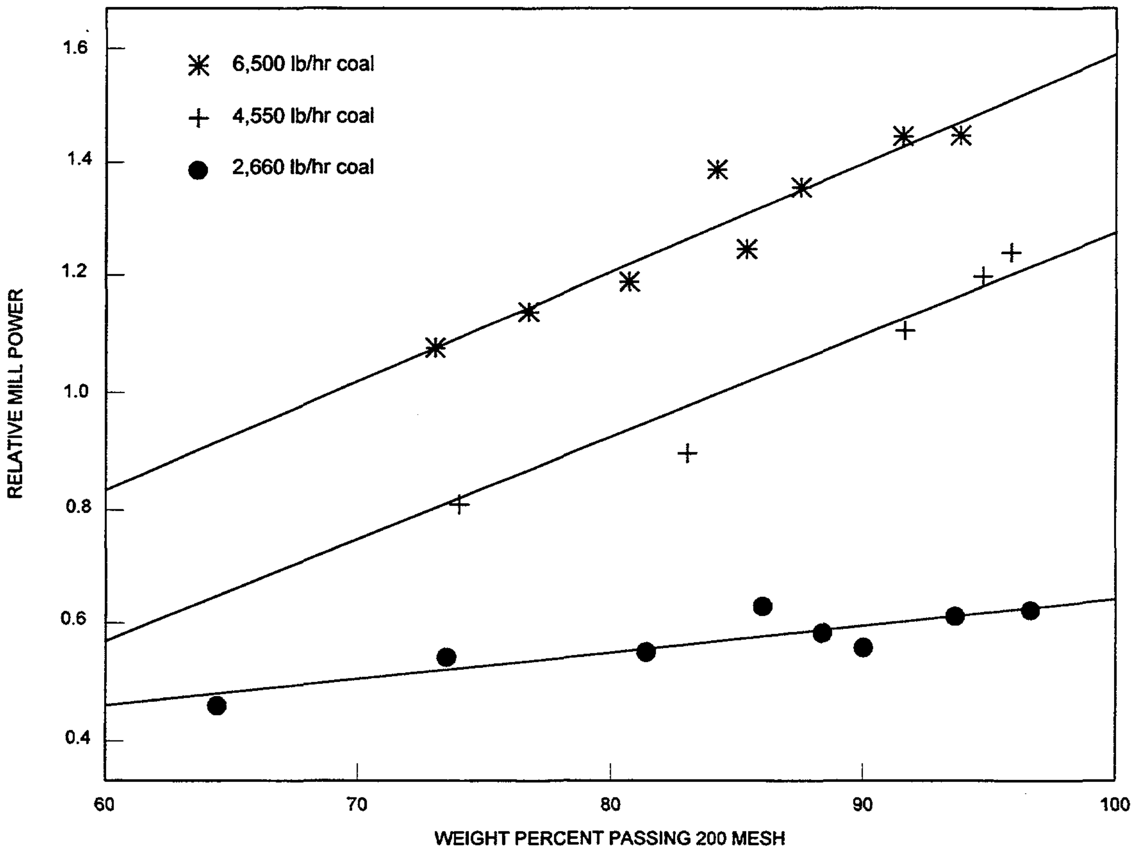



Figure 11-28 PDF Mill Power versus Fineness for Various Coal Rates HP1 Dynamic™ Classifier

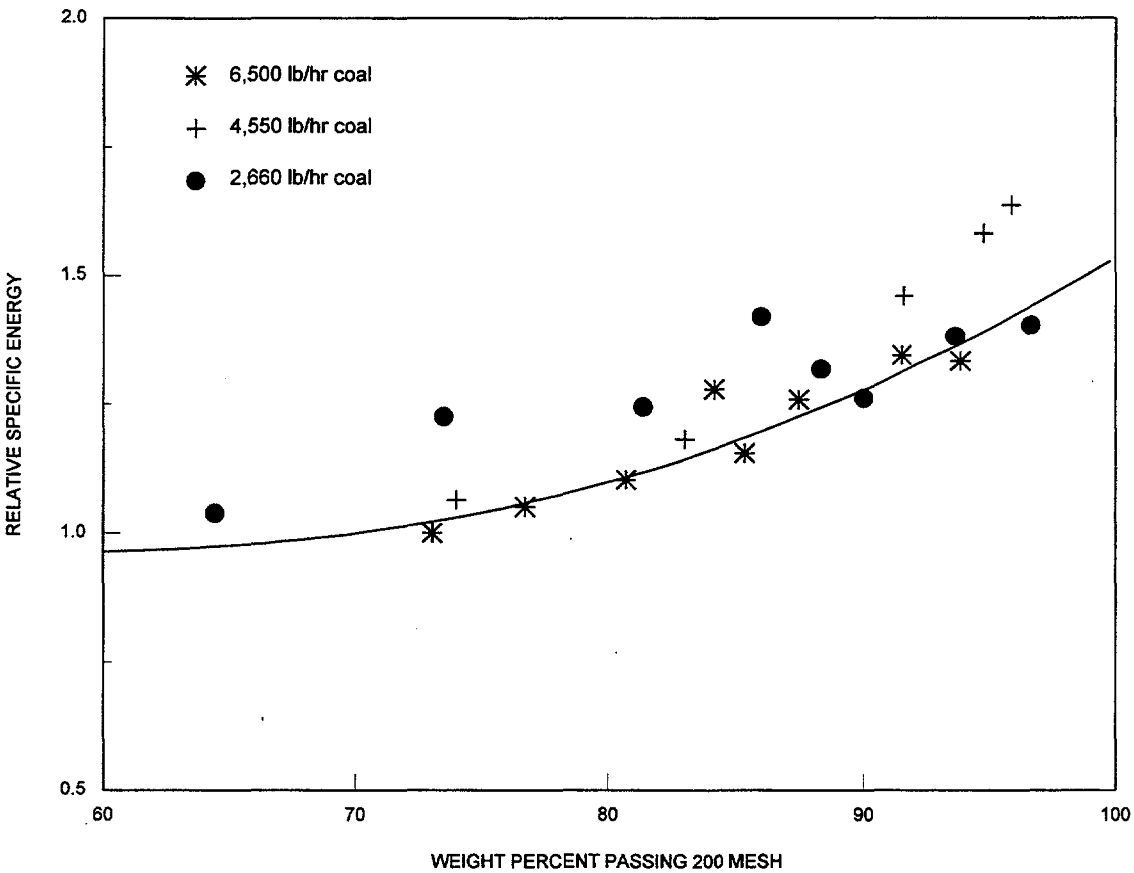



Figure 11-29 PDF Mill Specific Energy versus Fineness
HP1 Dynamic™ Classifier

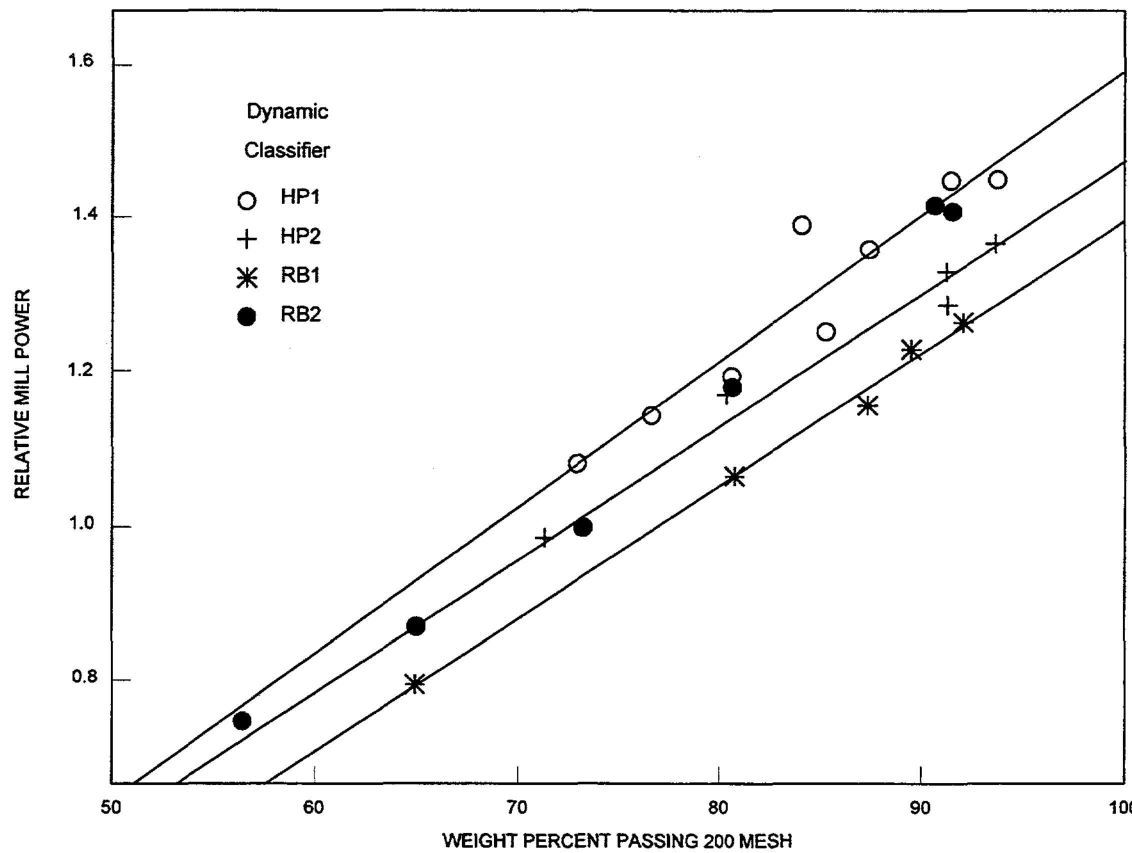



Figure 11-30 PDF Mill Power versus Fineness for Various Dynamic™ Classifier Designs

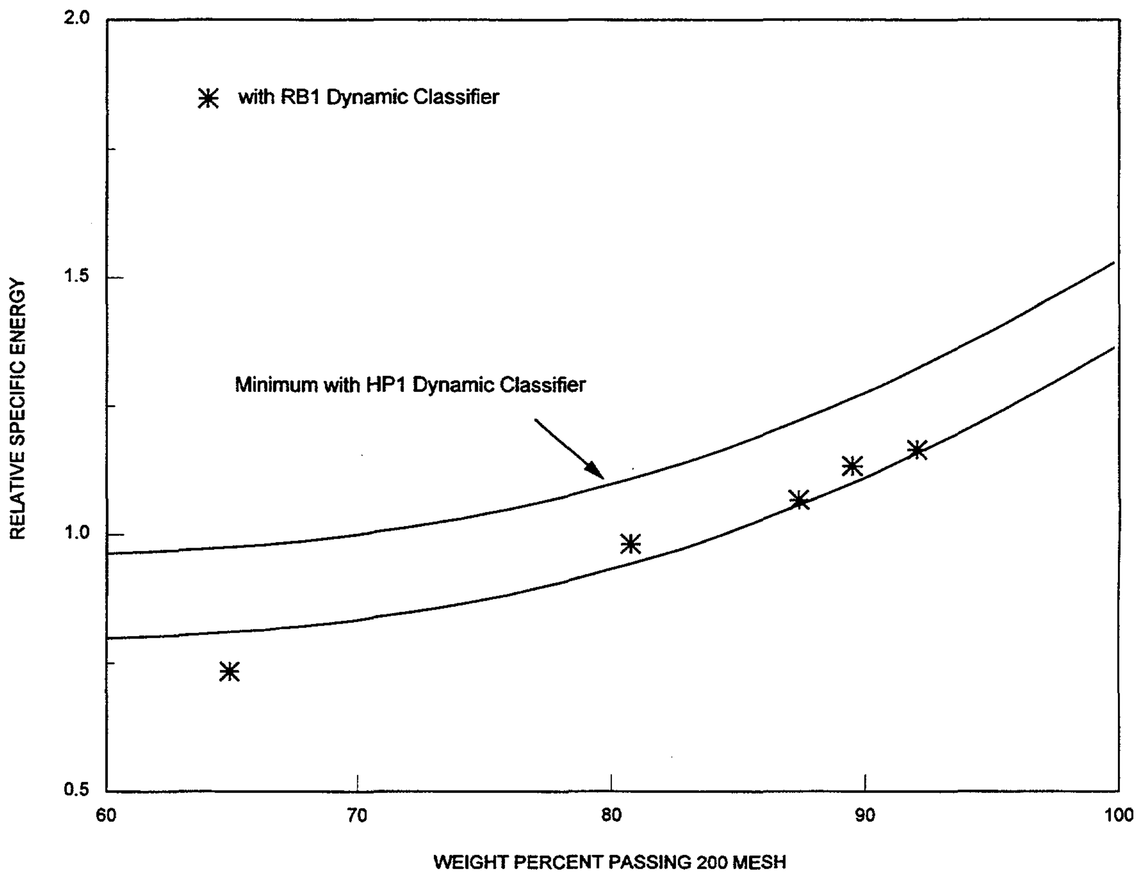



Figure 11-31 PDF Mill Specific Energy versus Fineness
HP1 and RB1 Dynamic™ Classifiers

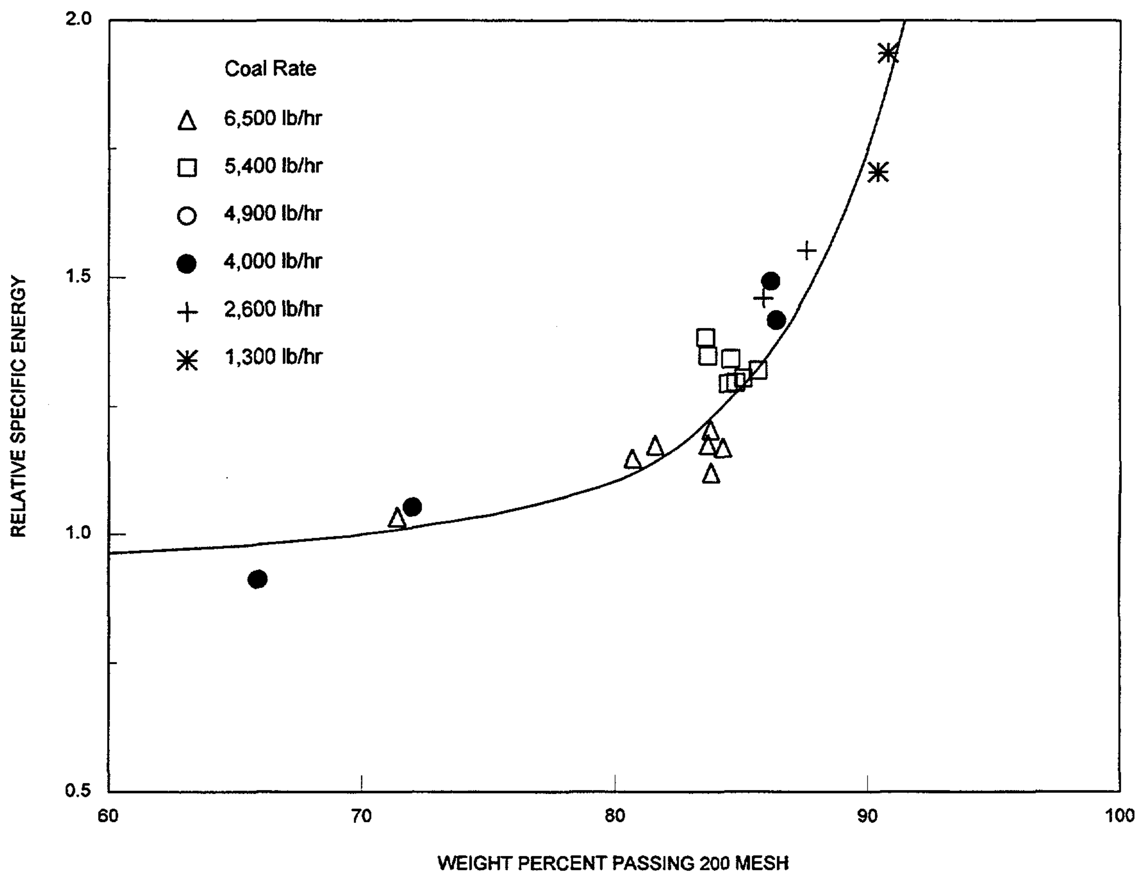



Figure 11-32 PDF Mill Specific Energy versus Fineness
Static Classifier

It is clear that a Dynamic™ classifier should be selected for the POCTF pulverizers. These classifiers provide greater flexibility with respect to the desired fuel size than static classifiers and require significantly less reduction of throughput to achieve very fine products. Final classifier design selection will depend on the pulverizer size selected for the POCTF. However, this classifier design will embody the characteristics found to be important in this investigation.

## TASK 12 - PHASE II REPORT

Work commenced on drafting the Phase II Report.

## PLANS FOR NEXT QUARTER

Task 1

- Deliver a paper at the First Joint Power & Fuel Systems Contractors Conference.
- Deliver a paper at the Thirteenth Annual International Pittsburgh Coal Conference.

Task 7

- Make a decision on future use of the CeraMem filter.

Task 8

- Complete preliminary designs of boiler, turbine/generator, heat exchangers, and NID system and the overall plant design.

Task 10

- Complete reconfiguration of the test rig for the 5,000 acfm CeraMem test if a decision is made to pursue future use of the CeraMem filter.

Task 11

- Initiate the 5,000 acfm CeraMem filter test if a decision is made to pursue use of the CeraMem filter.
- Submit Subtask 11.3 report.

Task 12

- Continuing drafting Phase II Report.

APPENDIX A - 2 pages

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(11-84)

U.S. DEPARTMENT OF ENERGY

**MILESTONE SCHEDULE** ☐PLAN ☒STATUS REPORT



FORM APPROVED
OMB 1901-1400

1. TITLE
Engineering Development of Advanced Coal-Fired Low-Emission Boiler Systems - Phases II & III

2. REPORTING PERIOD
October 1, 1994 - June 30, 1996

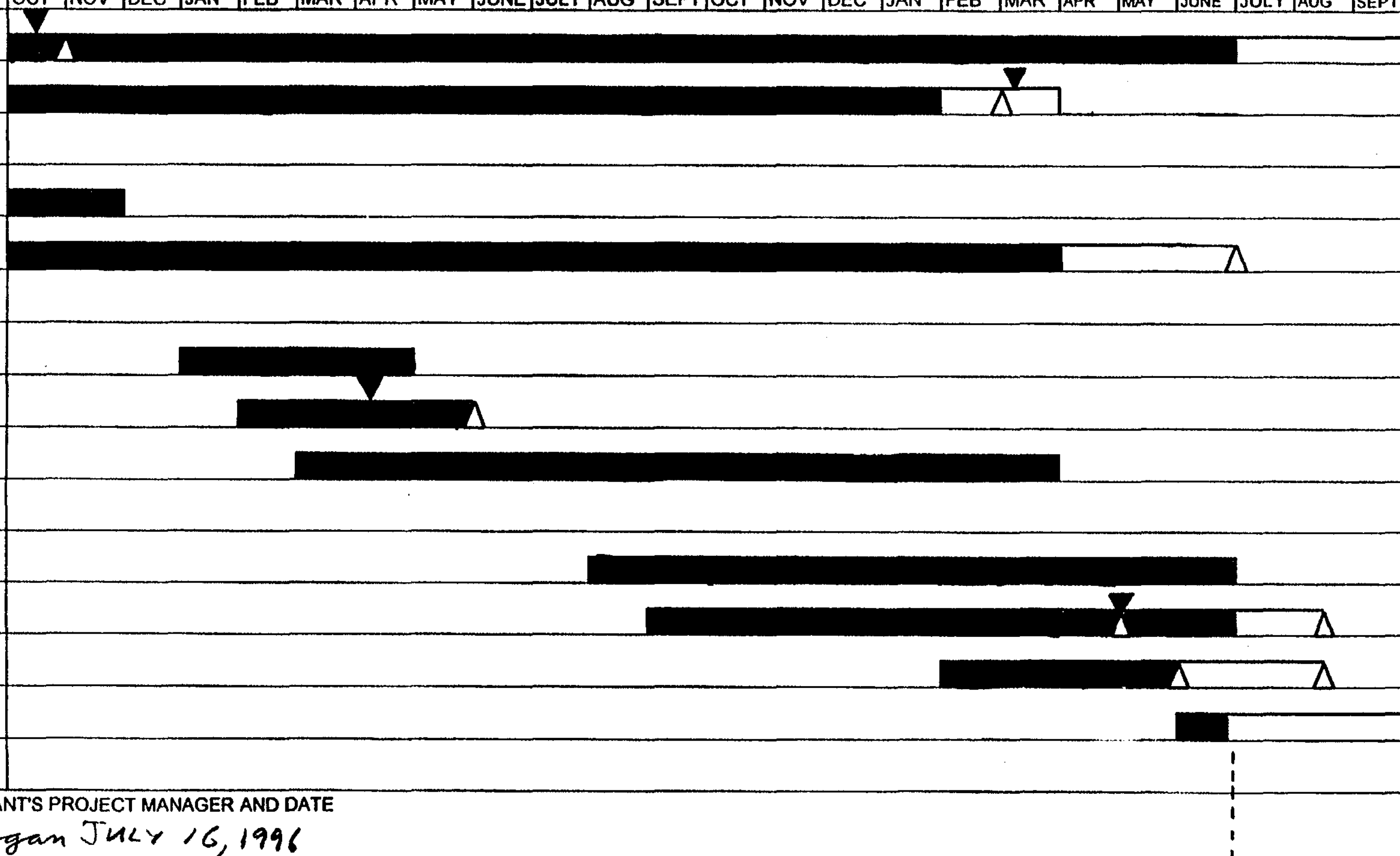
3. IDENTIFICATION NUMBER
DE-AC22-92PC92159

4. PARTICIPANT NAME AND ADDRESS
Combustion Engineering, Inc.
P.O. Box 500
Windsor, CT 06095-0500

5. START DATE
October 1, 1994

6. COMPLETION DATE
March 31, 1997

9. DURATION — FY95: OCT NOV DEC JAN FEB MAR APR MAY JUNE JULY AUG SEPT; FY96: OCT NOV DEC JAN FEB MAR APR MAY JUNE JULY AUG SEPT



| 7. ELEMENT CODE | 8. REPORTING ELEMENT | 10. PERCENT COMPLETE a. Plan | b. Actual |
|---|---|---|---|
| | PHASE II | | |
| 1.0 | Prj Mgt | 70 | 70 |
| 7.0 | Comp Dev | 100 | 89 |
| 8.0 | POCTF | | |
| 8.1 | Site Sel | 100 | 100 |
| 8.2 | Pre Dsn | 100 | 33 |
| 9.0 | Subsyst | | |
| 9.1 | Design | 100 | 100 |
| 9.2 | Plan | 100 | 100 |
| 10.0 | Constr | 100 | 100 |
| 11.0 | Subsyst | | |
| 11.1 | Oper | 100 | 100 |
| 11.2 | Test Ev | 90 | 90 |
| 11.3 | Dsn Ev | 90 | 67 |
| 12.0 | Draft Report | 51 | 21 |

11. SIGNATURE OF PARTICIPANT'S PROJECT MANAGER AND DATE
John W. Regan JULY 16, 1996

DOE F1332.3 X
(11-84)

U.S. DEPARTMENT OF ENERGY

**MILESTONE SCHEDULE ☐ PLAN ☒ STATUS REPORT**



FORM APPROVED
OMB 1901-1400

| | | |
|---|---|---|
| 1. TITLE<br>Engineering Development of Advanced Coal-Fired Low-Emission Boiler Systems - Phases II & III | 2. REPORTING PERIOD<br>October 1, 1994 - | 3. IDENTIFICATION NUMBER<br>DE-AC22-92PC92159 |
| 4. PARTICIPANT NAME AND ADDRESS<br>Combustion Engineering, Inc.<br>P.O. Box 500<br>Windsor, CT 06095-0500 | | 5. START DATE<br>October 1, 1994<br>6. COMPLETION DATE<br>March 31, 1997 |

| 7. ELEMENT CODE | 8. REPORTING ELEMENT | 9. DURATION FY97 | | | | | | FY | FY | 10. PERCENT COMPLETE a. Plan | b. Actual |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | PHASE III | OCT | NOV | DEC | JAN | FEB | MAR | | | | |
| 1.0 | Prj Mgt | | | | | | | | | | |
| 13.0 | CGU Dsn | | | | | | | | | | |
| 14.0 | POCTF | | | | | | | | | | |
| 14.1 | Rev Dsn | | | | | | | | | | |
| 14.2 | Test Plan | | | | | | | | | | |
| 15.0 | Report | | | | | | | | | | |

11. SIGNATURE OF PARTICIPANT'S PROJECT MANAGER AND DATE

John W. Regan

APPENDIX B - 2 Pages

CeraMem Filter Testing

## CeraMem Filter Testing (Task 7)

A 500-hour test on the original CeraMem catalytic filters was completed and operation was suspended 26 Apr due to an RP&L scheduled outage. The unit was operated for approximately 450 hours on flue gas. Particulate removal was successful, with analytical results indicating in excess of 99.3 % removal.

The filter was cleaned successfully, as evidenced by regeneration of tubesheet pressure differential. However, tubesheet differential pressure was higher than expected and increased with operating time.

Ammonia injection was successful, with analytical results showing a $NO_X$ reduction of approximately 35 % at a SR=0.3.

The unit was operated at the following conditions:

- Filtration temperature - approx. 650-675 F.
- Filter Face Velocity - approx. 2.5 - 4.5 ft/min.
- Pulse duration - 300 ms down to 100 ms, final value of 200 ms.
- Pulse dwell - 15 minutes, complete cycle (alternate firing of opposing solenoids fire on 7.5 minute schedule), extended to final value of 30 minutes, complete cycle (alternating firing of opposing solenoids every 15 minutes)
- Ammonia injection rate = 0.45 SCFM total gas, approximately 0.004 SCFM ammonia
- Ammonia stoichiometric ratio = approximately 0.3 maximum.
- $NO_X$ reduction = maximum of 30 %.

Tubesheet differential pressure started at approximately 16 inches water at FFV=4 and rose to approximately 23-24 inches water at FFV = 4. Tubesheet differential pressure stabilized at this value. At the end of half-dwell time, tubesheet differential pressure increases approximately 0.5-0.75 inch w.c.

The unit was opened for inspection and maintenance. The tubesheet "clean-side" did not show any evidence of ash, particularly in cracks and crevices. This tends to support that SRI numbers were reflective of particulate matter left in bypass ducts and not from particulate that was passing through the tubesheet.

Venturis were removed and inspected. A CAD drawing of the venturis was made. The venturis had two open 1/4" NPT couplings. The purpose of these couplings is not clear. Differential pressure due to the venturis was re-estimated according to the proper dimensions. The differential pressure due to the venturis was estimated at less than 2", without accounting for any effect due to the open couplings.

Filters were removed from the unit and inspected. "Clean-side" and "dirty-side" of filters were as expected. Each cell was plumbed with a guitar string to check for plugs. One channel (out of 684 total) was found to be plugged, reducing effectively length to approximately 80 %. Filters were shipped to CeraMem for testing and replacement.

Fluegas ammonia analysis was received from SRI, indicating that ammonia injection rates were below those expected by field calculations. SRI had also taken some samples of the ammonia gas mixtures directly from the bottles, and the results of this analysis confirm the lower ammonia injection rates.

The unit was reassembled and reinsulated.

Operation resumed 4 Jun with a 100 hour-test on a second set of catalytic filters. The second set of catalytic filters was installed and tested at higher $NH_3/NO_X$ (greater than 0.3) stoichiometries. Draft loss was similar to the previous set, indicating catalyst loading (space velocity) was approximately the same. Catalyst activity of the second filter set was the same as the first set, as indicated by performance at similar conditions. Results of catalytic testing indicated that maximum $NO_X$ reduction was approximately 75 % or to an average of 100 ppm $NO_X$ (7 % $O_2$) in the outlet flue gas. Ammonia slip was excessive (greater than 25 ppm) above approximately 50 % $NO_X$ reduction.

The unit was then taken off-line, cooled, and the catalytic filters were replaced with non-catalytic filters. Unit was brought back on-line 18 Jun for 500-hour test and was in operation until 28 Jun, when it was taken off-line. During that time, the unit was operated for approximately 180 hours, with one major problem. Due to an as-of-yet unidentified reason, air pressure in the cleaning air reservoir dropped to approximately 60 psi and the filters appear to have plugged. Filters were regenerated after header pressure returned to 100 psi and all cleaning air was forced through the filters by taking the unit off-line and closing all outlet valving. Preliminary results indicate that the non-catalytic filters have a draft loss of approximately 1/3 that of the catalytic filters.

APPENDIX C - 24 pages

Raytheon Engineers & Constructors Report on POCTF Plant Design

TECHNICAL PROGRESS REPORT
FOR THE PERIOD
APR. - JNE. 1996

FOR

ENGINEERING DEVELOPMENT OF ADVANCED COAL-FIRED
LOW EMISSIONS BOILER SYSTEMS

SUBMITTED TO:

ABB POWER PLANT LABORATORIES
COMBUSTION ENGINEERING, INC.
2000 DAY HILL ROAD
WINDSOR, CT 06095

RAYTHEON ENGINEERS & CONSTRUCTORS
30 S. 17TH ST.
PHILADELPHIA, PA 19103

JULY 1996

## SUMMARY

Sufficient equipment and system design information was completed by ABB on the major system packages to allow restart of Raytheon's Task 8.2 preliminary facility design activities. The key project team members were assigned, site visits were completed, and preparation of initial work products was completed.

The project licensing plan was revised to reflect the current project structure (Kalina/NID), and work on the long-lead permits was initiated per the plan.

## TASK 8: PRELIMINARY POC TEST FACILITY DESIGN

### Administrative

Sufficient equipment and system design information was received from ABB on the major system packages to allow restart of Raytheon's Task 8.2 activities as of the end of May. The key project team members were assigned and initial site visits to the Whitewater Valley station were made.

A revised schedule for Raytheon's preliminary design activities (Task 8.2) was developed based on a 14-week effort, that restarts work the last week in May and completes work the last week in August.

### POCTF Facility Design

#### Design Basis

The basis of the facility design is the (Kalina) cycle heat balance prepared by Exergy, and the equipment designs prepared by ABB to implement the cycle,

- Vapor Generator System,
- Turbine-Generator System,
- Cycle Heat Exchangers,

and the flue gas treatment process and equipment,

- NID System (New Integrated Desulfurization).

#### Plant Performance

The approach taken in establishing the size of the modified unit has been to maximize its generating capacity, consistent with making maximum use of existing plant infrastructure. Key plant performance parameters are summarized in Table 1. The values listed for the POCTF are to be regarded as preliminary, or target, values, as they are subject to change as the design evolves and undergoes optimization/refinement.

TABLE 1
UNIT 1 PERFORMANCE PARAMETERS

| *Thermal* | | Existing | POCTF (prelim.) | Change |
|---|---|---|---|---|
| Coal Heat Input | MMBtu/hr | 400 | 440 | +10% |
| Cooling Tower Load | MMBtu/hr | 216 | 215 | |
| Generator Output | MWe | 35.6 | 54.6 | |
| Auxiliary Load | MWe | 2.2 | 6.7 | |
| Net Unit Generation | MWe | 33.4 | 47.9 | + 43% |
| Net Unit Heat Rate | Btu/kWh | 12,000 | 9,200 | - 23% |
| *Environmental* | | | | |
| $SO_2$ | lb/MMBtu | 6.0 / 1.6(*) | 0.1 - 0.2 | / - 90% |
| $NO_x$ | lb/MMBtu | - / 0.5(*) | 0.1 - 0.2 | / - 70% |
| Particulates | lb/MMBtu | 0.19/ 0.19(*) | 0.01 | / - 95% |

(*) pre/post Phase II Clean Air Act Amendments (2000)

Project Scope

The major elements of the facility design are summarized in the following listing, and are discussed individually in the subsequent sections.

- Demolition of Existing Unit 1 Facilities

- Mechanical/Power Systems

  - 12 New Heat Cycle Systems
  - 10-15 New Auxiliary/Support Systems
  - New Mechanical Services Systems (HVAC)
  - 10-12 Modified Systems

- Process Systems

  - Modified Demin Water Production
  - Cycle Fluid Treatment: Chemical/Physical
  - Drains/Vents Collection & Handling
  - Evaluate/Modify Wastewater Treatment

- Electrical

    - ♦ High Voltage System (14.4 kV)
    - ♦ AC Distribution Systems
    - ♦ UPS & DC Systems
    - ♦ Lighting / Grounding / In-Plant Communications

- Civil / Structural

    - ♦ Site Preparation
    - ♦ Modify T/G Pedestal
    - ♦ Modify Boiler Support System & Boilerhouse
    - ♦ Heat Exchanger Building
    - ♦ Outside Foundations
    - ♦ Modify Circulating Water Flume

- Instrumentation & Control

    - ♦ New Distributed Control System (DCS)
    - ♦ New Instrumentation and Control Elements

<u>Demolition</u>

Due to the extensive amount of demolition work required on unit 1 to accomodate the Kalina retrofit, this aspect of the facility design is being developed as a specific engineering activity. The preliminary design work products include

- demolition drawings,
- definition of the scope of work, and a
- demolition specification.

This work was walked-down at the site with an initial demolition contractor, and a similar walk-down will be scheduled with a second contractor. The purpose of the contractor involvement is to have them submit budgetary quotes, schedule and approach.

Mechanical / Power

To identify the overall cycle configuration and quantify key process flow variables, process flow diagrams for the power cycle

- gas-side heat and mass balance,
- turbine heat balance,

were developed and are being refined. Preliminary versions of these diagrams are shown in Figures 1 and 2.

Following this basic definition of the cycle, the next step in development of the plant design is to define the plant's individual mechanical systems. The functional configuration of each system is presented on a piping and instrumentation diagram (P&ID), which identifies the individual items of (mechanical) equipment in the system, the piping configuration and size, the type and location of instrumentation and control elements, and key control logic. During the present reporting period, the P&ID's for the 12 power cycle systems were initiated and are in progress. Preliminary versions of two typical diagrams (without I&C content) are presented in Figures 3 and 4.

One of the areas of most significant effort is the development of the general arrangements for the facility. The unique nature of many of the Kalina components, the necessity to retrofit the new equipment into an existing plant, and the desire to evolve a compact, efficient arrangement, is requiring a substantial, original design effort. An overall concept for the facility arrangements was developed and is shown in Figure 5. The new vapor generator will be located in the existing boiler cavity in the boilerhouse (following removal of the old equipment), and the existing turbine pedestal will be modified to accept the new turbine/generator set. A new building will be added to the west side of the turbine hall to house the cycle heat exchangers and the new electrical distribution equipment. The area in the figure designated as "flue gas area" will contain the rotary-regenerative air heater, the NID system, and the FD/ID fans. All of the flue gas equipment will be located outdoors.

Initial work on the general arrangements has concentrated on the heat exchanger building, as this is the area involving the largest segment of design work. Initial versions of the arrangements, a plan and an elevation, are shown in Figures 6 and 7, respectively. The approach being used is to develop an initial layout to identify the size and spatial requirements of all of the equipment, and to then iterate the design to achieve optimized arrangements.

An initial estimate of pipe sizing for the heat cycle systems was developed, and is being used to develop the piping arrangements as shown in Figure 8. Following development of the pipe routing, the fluid pressure drops will be calculated and pipe sizing will be refined.

## Process

The cycle process design is evaluating working-fluid treatment requirements from plant input to plant output, including

- makeup water and ammonia for the cycle,
- chemical and physical treatment of fluid circulated within the cycle,
- collection of spent fluid (vents and drains),
- recovery or disposal of spent fluid, and
- the potential need to modify the existing wastewater treatment systems.

## Electrical

A main single-line diagram for the modified unit 1 electrical system is presented in Figure 9, showing the high voltage system for the generator output (14.4 kV) and in-house AC distribution at medium voltages (4160V and 2400V) and low voltage (480V).

A new high voltage system (14.4 kV) that carries the generator output from the generator terminals into the switchyard will be required because of the substantial increase in generated power. This system will make use of a spare main step-up transformer owned by RP&L, but will require new isophase bus duct out to the transformer and new cabling from the transformer into the switchyard.

As indicated in Table 1, the unit 1 auxiliary load will increase by about a factor of three, thus requiring that both unit 1 auxiliary transformers be replaced with higher-capacity transformers. These two transformers will feed two independent medium-voltage electrical systems (4160V and 2400V), each in a double-ended bus arrangement. The existing 2400V system will be maintained, but with some loads removed as dictated by the retrofit (e.g., boiler feed pumps, ID/FD fans, etc.). A new 4160V system will be added, and will feed the new large loads at this voltage, as well as feed (via stepdown transformers) the new 480V load centers and motor control centers (MCC's).

Based on inputs from the other disciplines and from the various ABB system packages, an initial electrical load list was developed. This load list has been used as the basis for the start of the individual electrical system single-line diagrams, and for the determination of capacity requirements for the electrical equipment. In addition, performance-type equipment specifications are being prepared for the major pieces of electrical equipment.

Preliminary arrangements for the new electrical distribution equipment are shown in Figure 10. The medium-voltage switchgear will be located on a platform in the turbine hall between the two pedestals, and at the same elevations as the pedestals. This location provides convenient access to the auxiliary transformers to the north of the building that feed this switchgear. The new 480V load centers and MCC's, as well as other miscellaneous electrical equipment, will be housed in a low-bay area at the west end of the heat exchanger building.

### Structural

While work was underway by other disciplines to develop the various input information required for the design of most of the structural modifications (e.g., new boiler loads and arrangements, heat exchanger building size/arrangements), design of the turbine pedestal modifications were prepared.

The new turbine/generator train is shown in Figure 11, and consists of two individual turbines (hp and lp) coupled through a set of reducing gears and driving the generator on the far end of the lp shaft. This arrangement is in contrast to the existing generating train that incorporates only a single-casing turbine. Consequently the new train is longer and the pedestal must be extended to accomodate this increased length. The pedestal modifications, shown in Figure 12, involve the installation of an additional set of pedestal columns constructed from reinforced concrete and these columns are then tied to the existing pedestal with horizontal steel members.

### Instrumentation & Control

The primary I&C activities, in the current reporting period, were the preparation of a specification for the distributed control system (DCS), development of an initial estimate of the I/O count for the control system, and addition of I&C content to the piping and instrumentation diagrams.

## Licensing

A revision of the project licensing plan was prepared that incorporates the addition of the Kalina cycle to the project, and the replacement of the $SNO_x$™ system with the NID system for flue gas treatment. This plan is summarized in Table 2. As indicated in the table, the plan is structured to have all project permit approvals in hand by the end of September, 1997.

Review comments were incorporated in the revised DOE Environmental Questionaire and it was issued to ABB for subsequent submittal to DOE PETC. This revision incorporated the restructuring of the project design basis described above (e.g., Kalina/NID).

A letter to the state, requesting a determination of PSD nonapplicability for the project, was drafted and has been submitted to RP&L for review.

Work was started on the long-lead permits, with effort concentrated on the Title V permit dealing with accidental (ammonia) release.

**TABLE 2**
**LOW-EMISSION BOILER SYSTEM PROJECT**
**PROJECTED LICENSING SCHEDULE**

| No | Potentially Required Permit or Approval | Start of Environ. Work | Applic. Submittal Date | Expected Approval Date | Regulatn Time Limit |
|---|---|---|---|---|---|
| 1 | PSD Nonapplicability Determin. | 5/96 | 7/96 | 8/96 | 30 days |
| 2 | NSPS Air Permit | 6/96 | 9/96 | 5/97 | 270 days [a] |
| 3 | APCD Construction Permit | 6/96 | 9/96 | 5/97 | 270 days [a] |
| 4 | Title V Operating Permit | 6/96 | 9/96 | 5/97 | 270 days [a] |
| 5 | Title V Permit-Accidental Release [c] | 6/96 | 11/96 | 9/97 | None [b] |
| 6 | NPDES Permit Modification: | | | | |
| | Construction Activity Runoff [d] | 8/96 | 10/96 | 11/96 | None |
| | NormalWastewater Discharge | 8/96 | 10/96 | 9/97 | 365 days |
| 7 | Industrial Wastewater Treatment Facility Construction Permit [e] | 8/96 | 10/96 | 1/97 | 60 days |
| 8 | Soil Erosion-Sediment Contrl Plan | 8/96 | 10/96 | 9/97 | None |
| 9 | DOE FONSI: | | | | |
| | Environmental Questionaire | 3/96 | 4/96 | 7/96 | None |
| | Environ. Information Documnt | 7/96 | 11/96 | 5/97 | None |
| 10 | Pollution Contingency Plan | 7/96 | 11/96 | 1/97 | None |
| 11 | Community Right To Know Rept. | 7/96 | 11/96 | 1/9 | None |
| 12 | NESHAP Permit-Asbestos [e] | - | - | - | None |
| 13 | Solid Wate Management Permit [e] | - | - | - | None |

NOTES:
a. - Add 45 days if IDEM determines that a public hearing is required.
b. - EPA has only proposed the Risk Management Plan portion of the regulation at this time. The proposal assumes that the applicant will expand on the OSHA requirement that a process hazard analysis be prepared for worker safety, i.e., expanded to include the impact on public health and the environment.
c. - This work assumes that engineering's process hazard analysis to meet the OSHA requirement will expanded, using modeling, to address environmental impacts.
d. - IDEM "invites" applications for this permit for projects which will disturb between 1 and 5 acres of land since a pending federal court decision may impose this requirement on this level of activity.
e. - Listed as a potential requirement only, with its actual need dependent on the final design of the facility.

## PLANS FOR THE NEXT REPORTING PERIOD

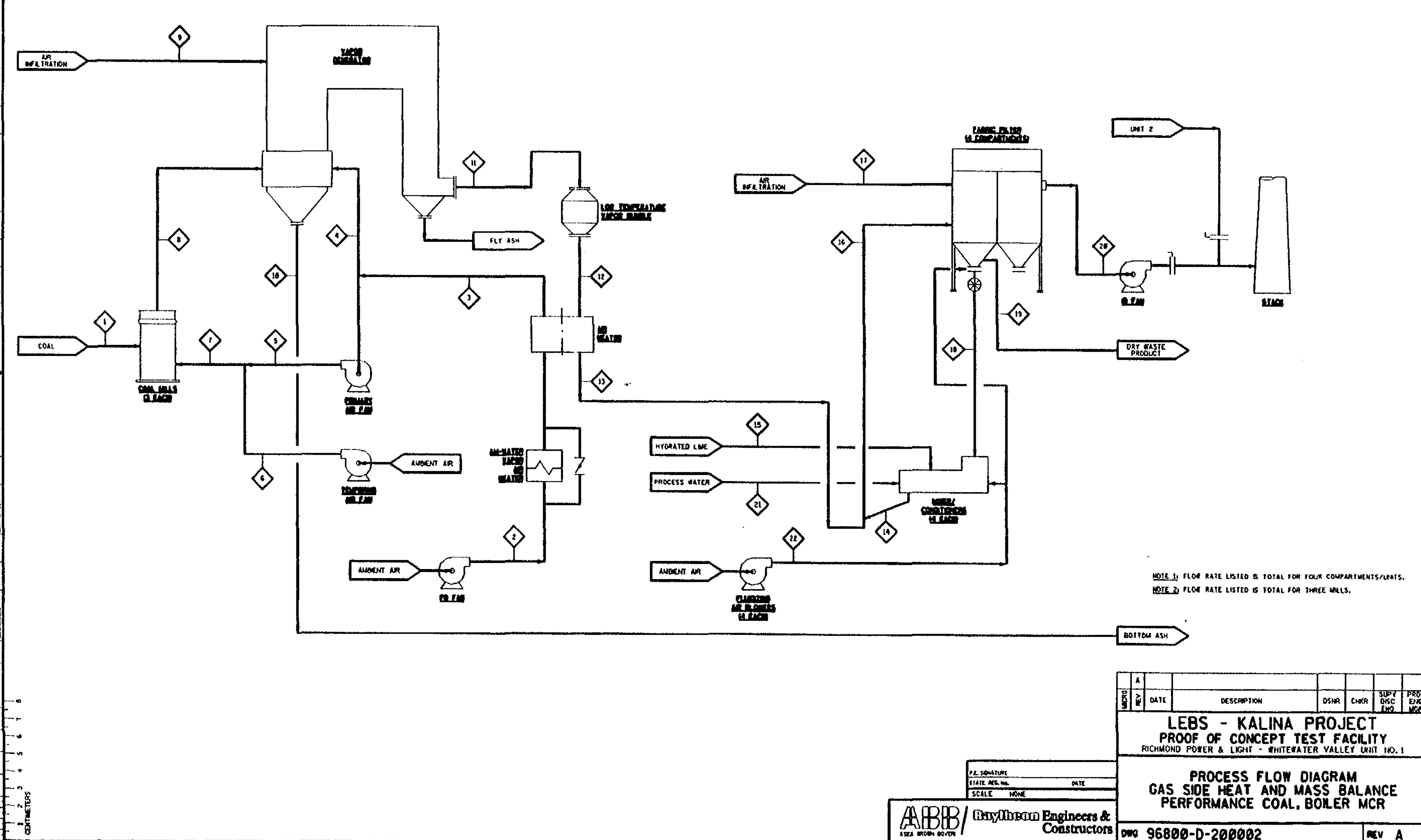
The balance of the POCTF preliminary design work is expected to be completed in the next reporting period.

Work will continue on the licensing effort per the revised plan.

Dave Bender

D. J. Bender

| STATE | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 | 21 | 22 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| GAS FLOW (LBS/HR) | --- | 385,000 | 345,000 | 282,150 | 60,100 | 55,500 | 123,600 | 128,445 | 0 | --- | 447,000 | 447,000 | 486,400 | --- | --- | --- | 14,222 | --- | | | --- | |
| SOLID/LIQUID FLOW (LBS/HR) | 39,815 | --- | --- | --- | --- | --- | --- | 34,970 | --- | 666 | 2551 | 2551 | 2551 | --- | --- | --- | --- | --- | --- | 4 | --- | --- |
| TOTAL MASS FLOW (LBS/HR) | 39,815 | 385,000 | 345,000 | 282,150 | 60,100 | 55,500 | 123,600 | 163,415 | 0 | 666 | 449,551 | 449,551 | 488,951 | | | | 14,222 | | | | | |
| TEMPERATURE (°F) | 60 | 90 | 645 | 644 | 645 | 90 | 395 | 180 | 90 | --- | 190 | --- | 321 | 157 | 60 | --- | 60 | --- | --- | --- | --- | 60 |
| PRESSURE (IN. W.G.) | --- | +12.5 | +10.65 | +7.0 | +30.0 | +30.0 | +30.0 | --- | +0.0 | --- | -5.5 | --- | --- | --- | --- | --- | +0.0 | --- | --- | --- | --- | --- |
| DESCRIPTION | HHV=11,428 Q=455.01 | AIR HEATER AIR IN | PREHEATED AIR | SECONDARY AIR | HOT PRIMARY AIR | COLD PRIMARY AIR | MILL AIR | COAL AIR | | BOTTOM ASH | BACKPASS GAS OUT | AIR HEATER GAS IN | AIR HEATER GAS OUT | | $Ca(OH)_2$ | | | | | ID FAN INLET | | |
| REMARKS | SEE NOTE 2 | | | | SEE NOTE 2 | SEE NOTE 2 | SEE NOTE 2 | SEE NOTE 2 | | | | | | SEE NOTE 1 | SEE NOTE 1 | SEE NOTE 1 | TOTAL FOR BAGHOUSE | SEE NOTE 1 | SEE NOTE 1 | | SEE NOTE 1 | SEE NOTE 1 |



n:\prj\9680008\mic\pid\200002.dgn Jul. 11, 1996 08:17:37

Fig. 1

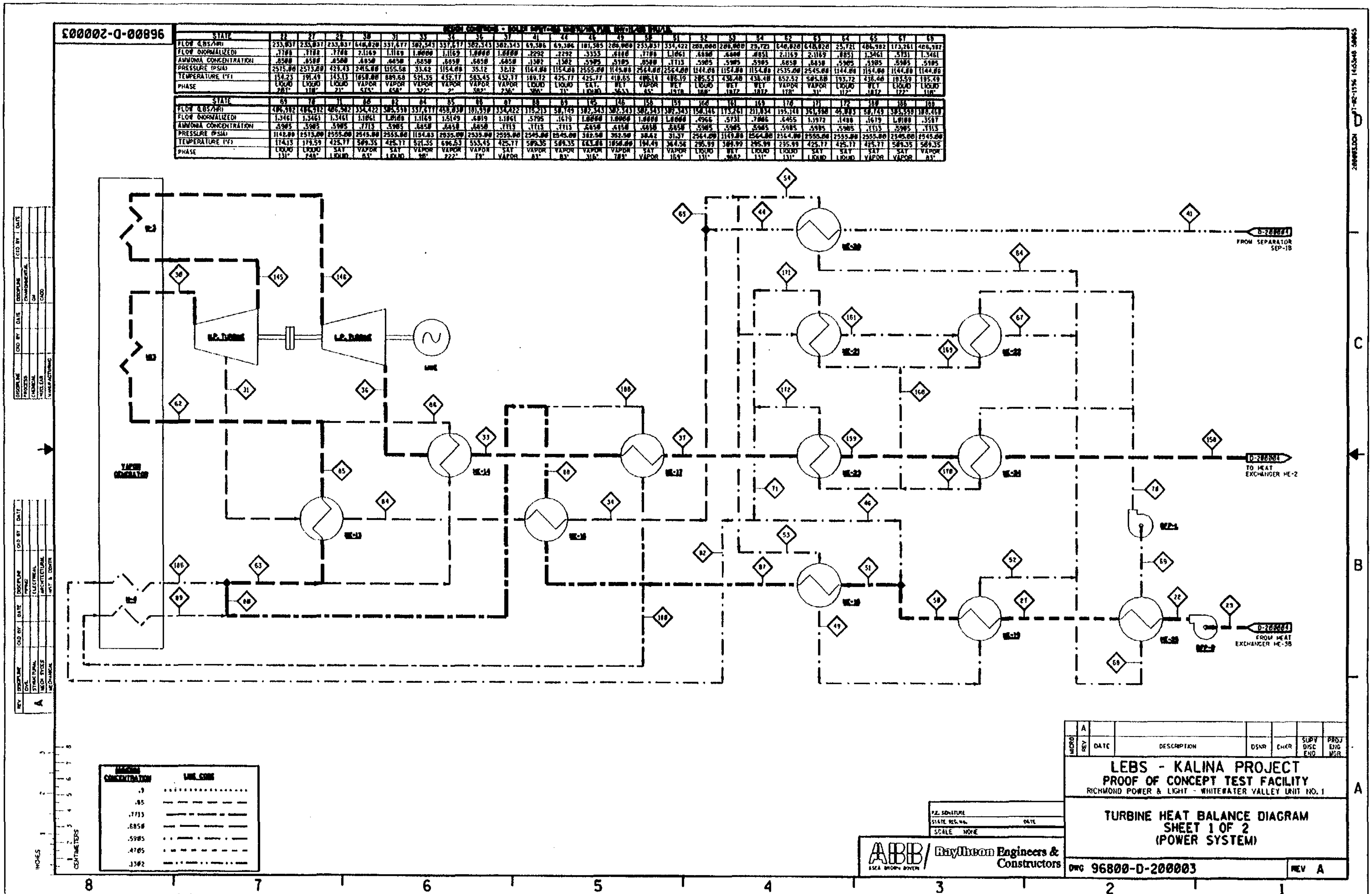


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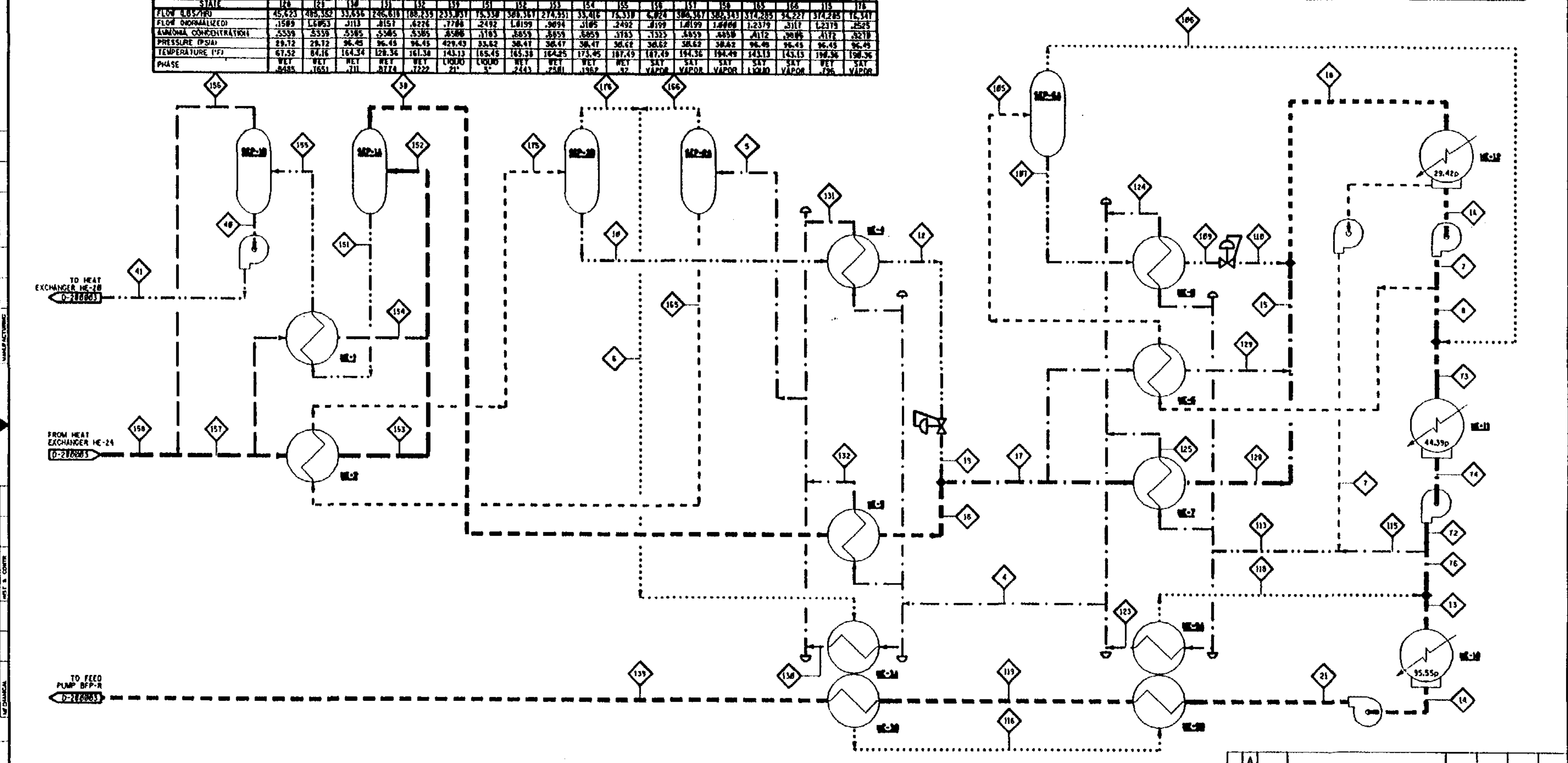
Fig. 2-A

96800-D-200004

| STATE | 1A | 2 | 4 | 5 | 6 | 7 | 8 | 10 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 21 | 30 | 40 | 41 | 72 | 73 | 74 | 76 | 105 | 106 | 107 | 109 | 110 | 113 | 115 | 116 | 118 | 119 | 123 | 124 | 125 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| FLOW (LBS/HR) | 673,948 | 673,948 | 468,512 | 468,512 | 176,574 | 150,111 | 314,684 | 297,938 | 297,938 | 233,837 | 233,837 | 536,975 | 233,837 | 536,975 | 824,858 | 297,938 | 233,837 | 233,837 | 69,306 | 69,306 | 380,864 | 380,864 | 380,864 | 62,463 | 359,264 | 66,188 | 293,883 | 293,883 | 293,883 | 468,512 | 318,482 | 176,574 | 176,574 | 233,837 | 12,031 | 285,235 | 171,246 |
| FLOW (NORMALIZED) | 2.2291 | 2.2291 | 1.5496 | 1.5496 | .5642 | .4965 | 1.0408 | .9854 | .9854 | .7708 | .7708 | 1.7562 | .7708 | 1.7562 | 2.7256 | .9854 | .7708 | .7708 | .2292 | .2292 | 1.2597 | 1.2597 | 1.2597 | .2066 | 1.1883 | .2189 | .9694 | .9694 | .9694 | 1.5496 | 1.0531 | .5642 | .5642 | .7708 | .0398 | .9434 | .5664 |
| AMMONIA CONCENTRATION | .4185 | .4185 | .5385 | .5385 | .9566 | .4185 | .4185 | .2866 | .2866 | .8500 | .8500 | .5339 | .8500 | .5339 | .4185 | .2866 | .8500 | .8500 | .1382 | .1382 | .5588 | .5588 | .5588 | .5588 | .4185 | .9785 | .3558 | .3558 | .3558 | .5385 | .5588 | .9566 | .9566 | .8500 | .5385 | .5385 | .9389 |
| PRESSURE (PSIA) | 29.42 | 48.54 | 99.45 | 96.45 | 96.45 | 103.45 | 48.54 | 96.45 | 96.45 | 95.85 | 95.55 | 29.72 | 30.32 | 30.32 | 29.72 | 30.32 | 436.43 | 30.47 | 30.62 | 1164.88 | 103.45 | 44.54 | 44.39 | 103.45 | 44.54 | 44.54 | 44.54 | 44.54 | 29.72 | 103.45 | 103.45 | 96.38 | 95.85 | 431.43 | 99.45 | 99.45 | 99.45 |
| TEMPERATURE (°F) | 62.00 | 62.07 | 113.59 | 143.13 | 168.34 | 62.20 | 62.07 | 190.36 | 121.49 | 89.32 | 62.06 | 82.60 | 121.59 | 121.59 | 85.42 | 121.59 | 63.28 | 165.38 | 187.49 | 189.72 | 62.14 | 88.69 | 62.00 | 62.14 | 117.59 | 117.59 | 117.59 | 66.60 | 66.64 | 62.18 | 62.14 | 117.59 | 74.68 | 113.91 | 113.59 | 113.59 | 113.59 |
| PHASE | SAT LIQUID | LIQUID 25° | SAT LIQUID | WET .1989 | WET .6821 | LIQUID 63° | LIQUID 25° | SAT LIQUID | LIQUID 69° | WET .414 | SAT LIQUID | WET .1718 | WET .1618 | WET .6321 | WET .865 | SAT LIQUID | LIQUID 182° | SAT VAPOR | SAT LIQUID | LIQUID 386° | LIQUID 41° | WET .8444 | SAT LIQUID | LIQUID 41° | WET .8158 | SAT VAPOR | SAT LIQUID | LIQUID 51° | LIQUID 30° | LIQUID 53° | LIQUID 47° | WET .0754 | WET .1631 | LIQUID 58° | SAT LIQUID | SAT LIQUID | SAT LIQUID |

| STATE | 120 | 121 | 130 | 131 | 132 | 139 | 151 | 152 | 153 | 154 | 155 | 156 | 157 | 158 | 165 | 166 | 175 | 176 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| FLOW (LBS/HR) | 45,623 | 485,352 | 33,656 | 246,610 | 188,235 | 233,837 | 75,330 | 308,367 | 274,951 | 33,416 | 75,330 | 6,024 | 308,367 | 302,343 | 314,285 | 94,227 | 374,285 | 16,341 |
| FLOW (NORMALIZED) | .1509 | 1.6053 | .1113 | .8157 | .6226 | .7708 | .2492 | 1.0199 | .9094 | .1105 | .2492 | .0199 | 1.0199 | 1.0000 | 1.2379 | .3117 | 1.2379 | .2525 |
| AMMONIA CONCENTRATION | .5339 | .5339 | .5385 | .5385 | .5385 | .8500 | .1183 | .6859 | .6859 | .6059 | .1183 | .1323 | .6859 | .6850 | .4172 | .9085 | .4172 | .9218 |
| PRESSURE (PSIA) | 29.12 | 29.12 | 96.45 | 96.45 | 96.45 | 429.43 | 33.62 | 30.47 | 30.47 | 30.47 | 30.62 | 30.62 | 30.62 | 30.42 | 96.45 | 96.45 | 96.45 | 96.45 |
| TEMPERATURE (°F) | 67.52 | 84.16 | 164.34 | 128.36 | 161.30 | 143.13 | 165.45 | 165.38 | 164.25 | 173.45 | 187.49 | 187.49 | 194.36 | 194.49 | 143.13 | 143.13 | 190.36 | 190.36 |
| PHASE | WET .8485 | WET .7651 | WET .711 | WET .8774 | WET .7222 | LIQUID 21° | LIQUID 3° | WET .2443 | WET .2581 | WET .1962 | WET .92 | SAT VAPOR | SAT VAPOR | SAT VAPOR | SAT LIQUID | SAT VAPOR | WET .796 | SAT VAPOR |




| AMMONIA CONCENTRATION | LINE CODE |
|---|---|
| .9276, .9566, .9785, .9806 | |
| .85 | |
| .6850, .6859, .7323 | |
| .5385, .5339, .5588 | |
| .4172, .4185 | |
| .1382, .1183, .2066, .3558 | |

| MICRO | REV | DATE | DESCRIPTION | DSNR | CHKR | SUPV DISC ENG | PROJ ENG MGR |
|---|---|---|---|---|---|---|---|
| | A | | | | | | |

LEBS - KALINA PROJECT
PROOF OF CONCEPT TEST FACILITY
RICHMOND POWER & LIGHT - WHITEWATER VALLEY UNIT NO. 1

TURBINE HEAT BALANCE DIAGRAM
SHEET 2 OF 2
(DISTILLATION SYSTEM)

P.E. SIGNATURE
STATE REG. No. DATE
SCALE NONE

ABB / Raytheon Engineers & Constructors

DWG 96800-D-200004 REV A

n: \prj\9680008\mic\pid\200004.dgn Jul. 11, 1996 08:23:22

Fig. 2-B

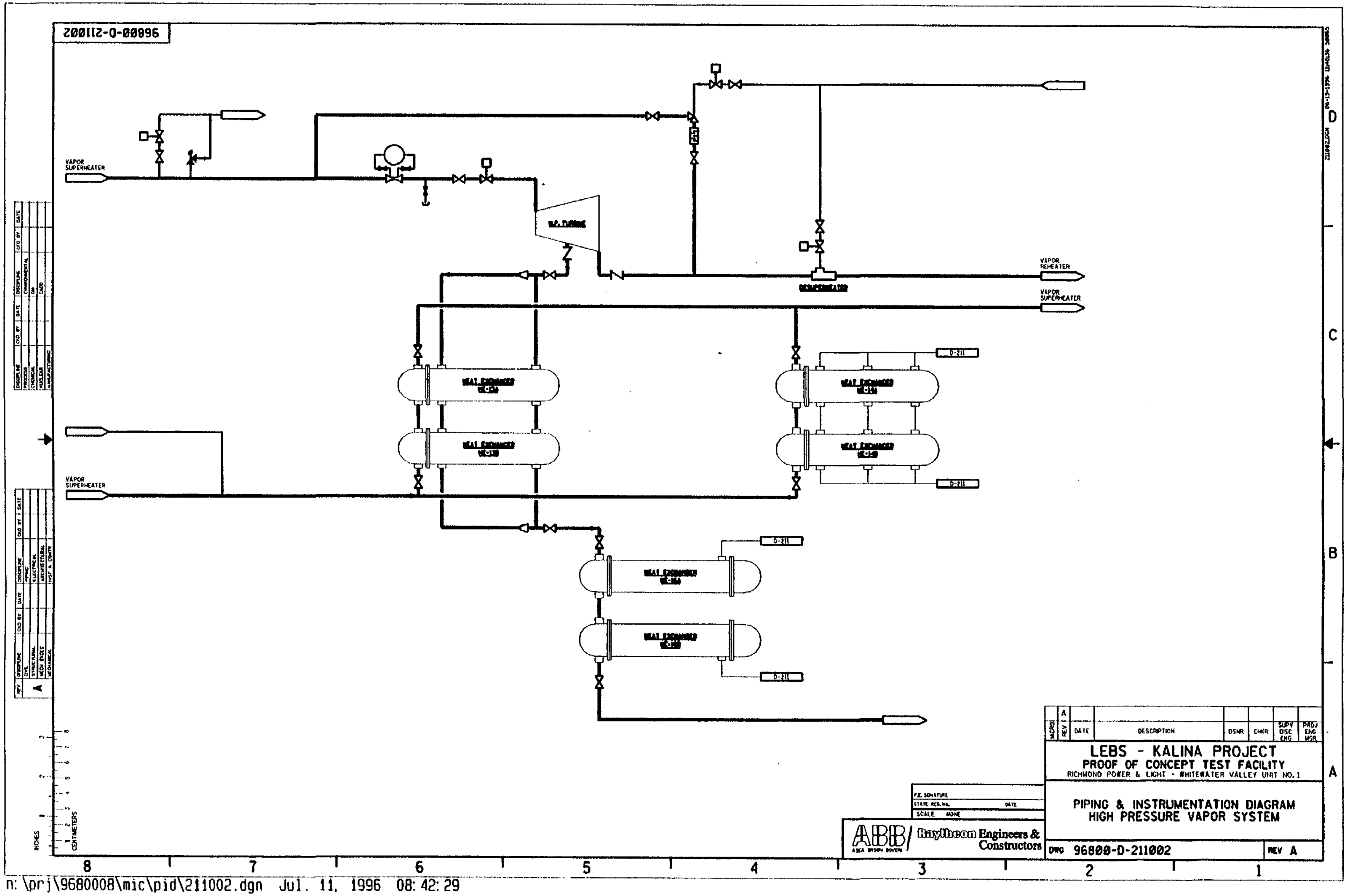

96800-D-211002
VAPOR SUPERHEATER
VAPOR REHEATER
VAPOR SUPERHEATER
VAPOR SUPERHEATER
D-211
D-211
D-211
D-211
LEBS - KALINA PROJECT
PROOF OF CONCEPT TEST FACILITY
RICHMOND POWER & LIGHT - WHITEWATER VALLEY UNIT NO. 1
PIPING & INSTRUMENTATION DIAGRAM
HIGH PRESSURE VAPOR SYSTEM
DWG 96800-D-211002
REV A
Raytheon Engineers & Constructors
SCALE NONE

Fig. 3

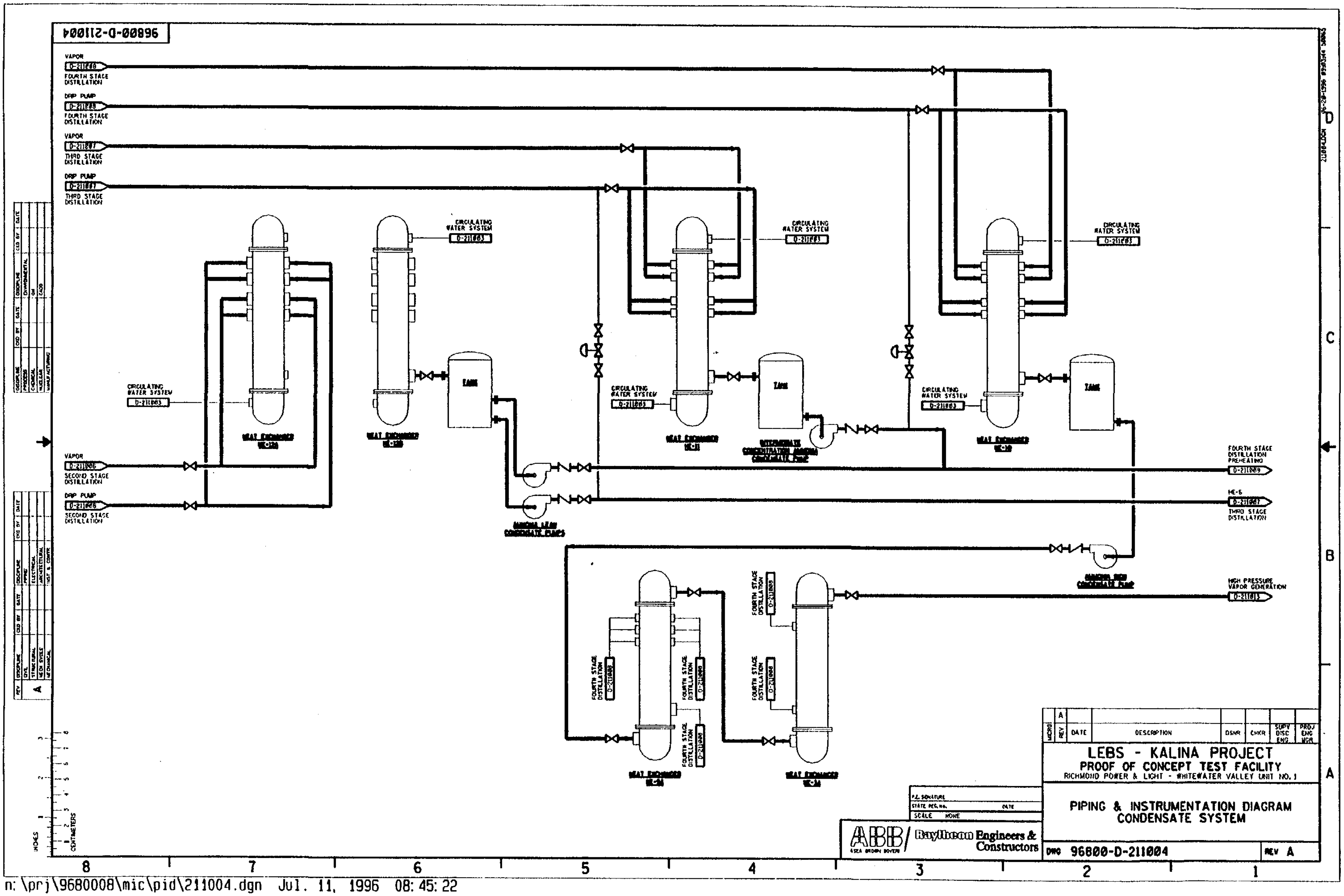

96800-D-211004
VAPOR
FOURTH STAGE DISTILLATION
DRIP PUMP
FOURTH STAGE DISTILLATION
VAPOR
THIRD STAGE DISTILLATION
DRIP PUMP
THIRD STAGE DISTILLATION
VAPOR
SECOND STAGE DISTILLATION
DRIP PUMP
SECOND STAGE DISTILLATION
CIRCULATING WATER SYSTEM
TANK
FOURTH STAGE DISTILLATION PREHEATING
THIRD STAGE DISTILLATION
HIGH PRESSURE VAPOR GENERATION
FOURTH STAGE DISTILLATION
LEBS - KALINA PROJECT
PROOF OF CONCEPT TEST FACILITY
RICHMOND POWER & LIGHT - WHITEWATER VALLEY UNIT NO. 1
PIPING & INSTRUMENTATION DIAGRAM
CONDENSATE SYSTEM
ABB / Raytheon Engineers & Constructors
DWG 96800-D-211004
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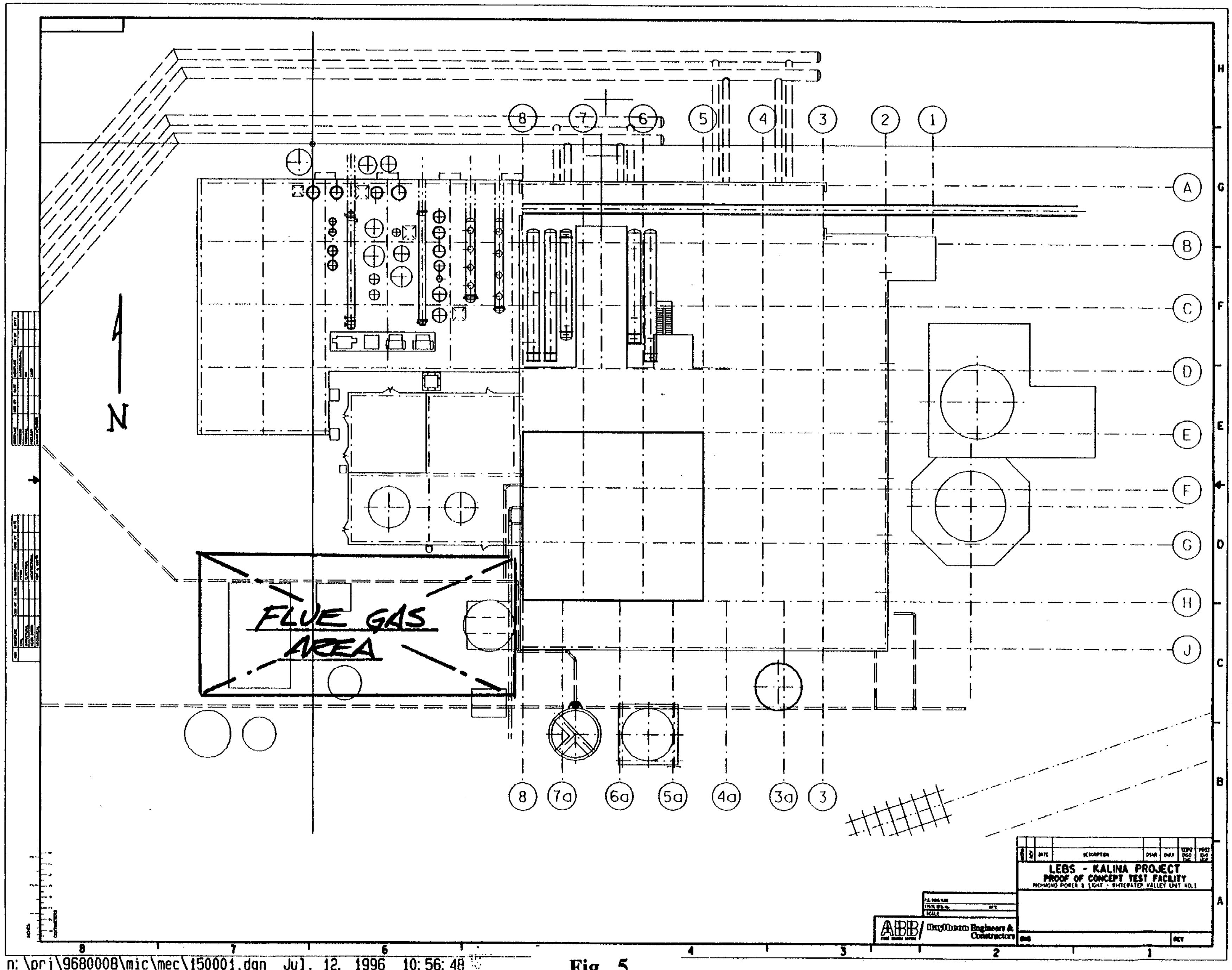
Fig. 4



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PROOF OF CONCEPT TEST FACILITY
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Fig. 5

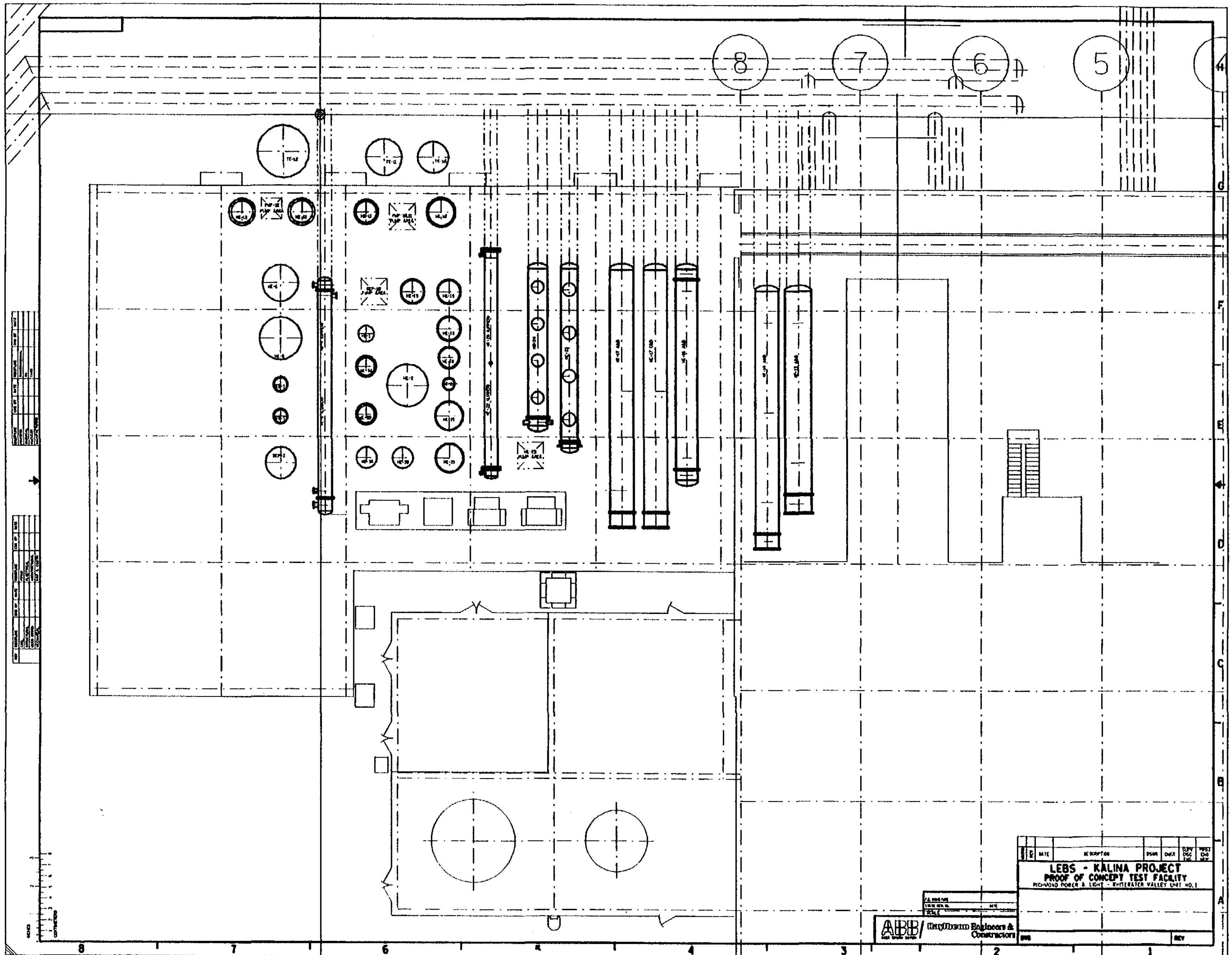

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Fig. 6

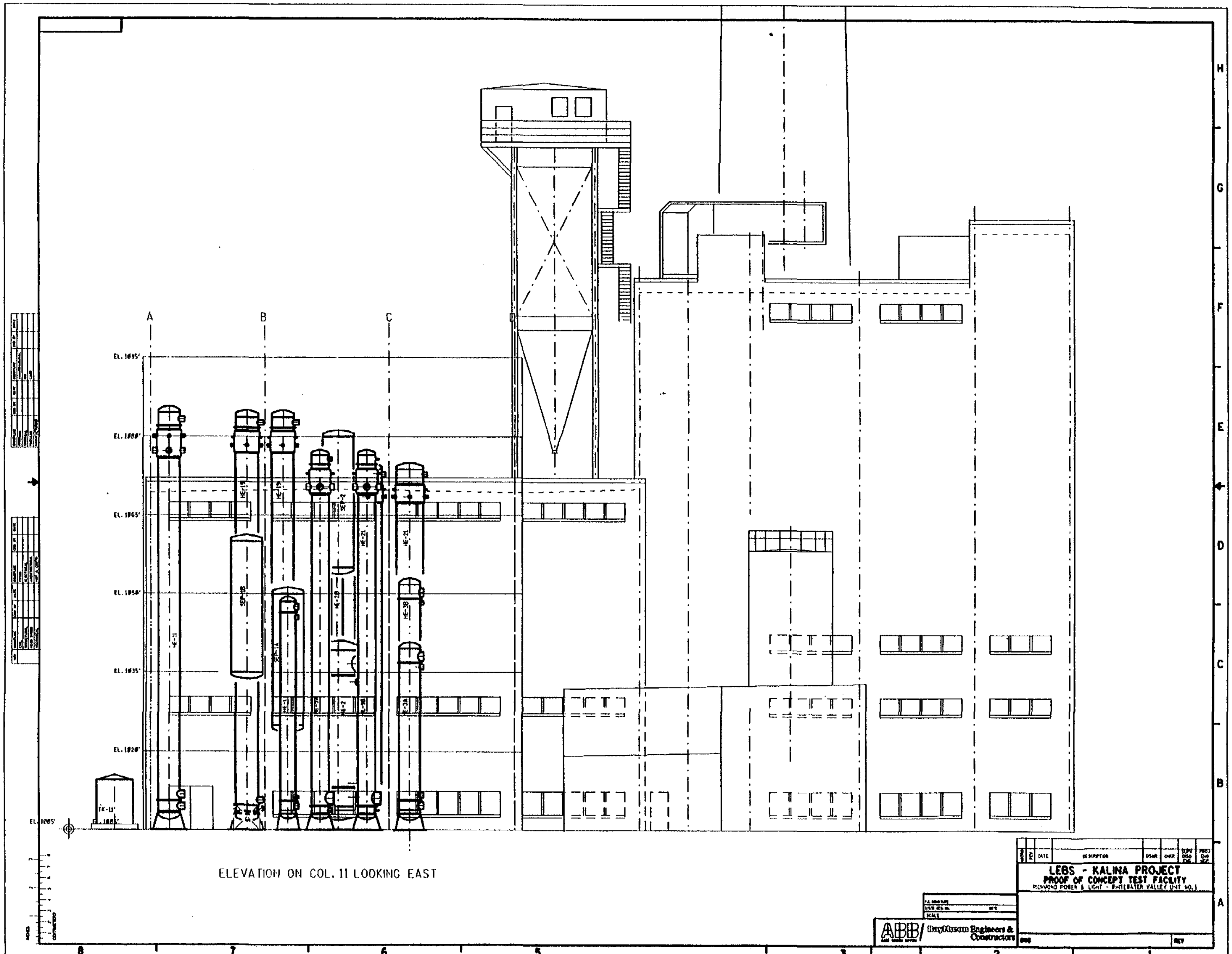


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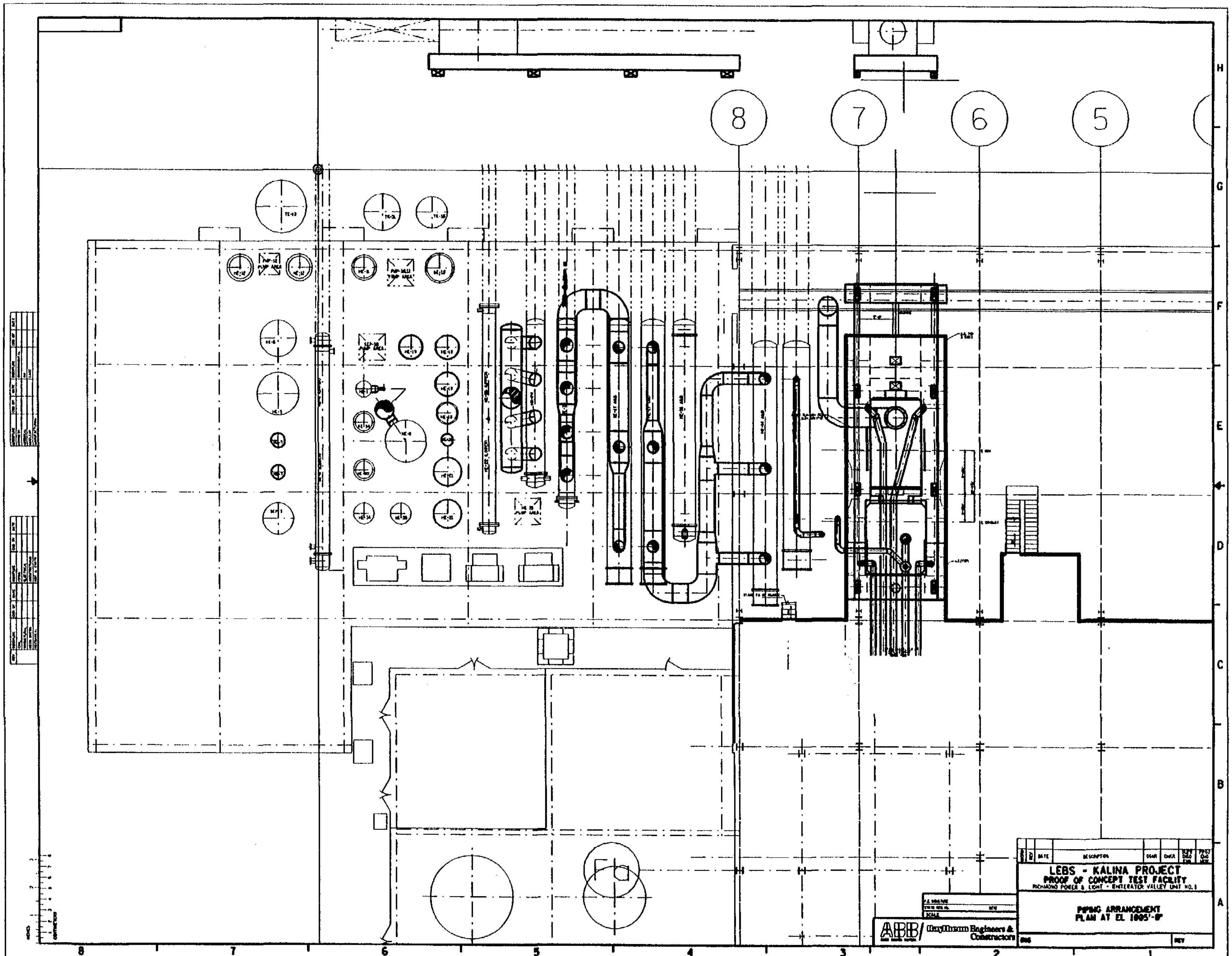
Fig. 7



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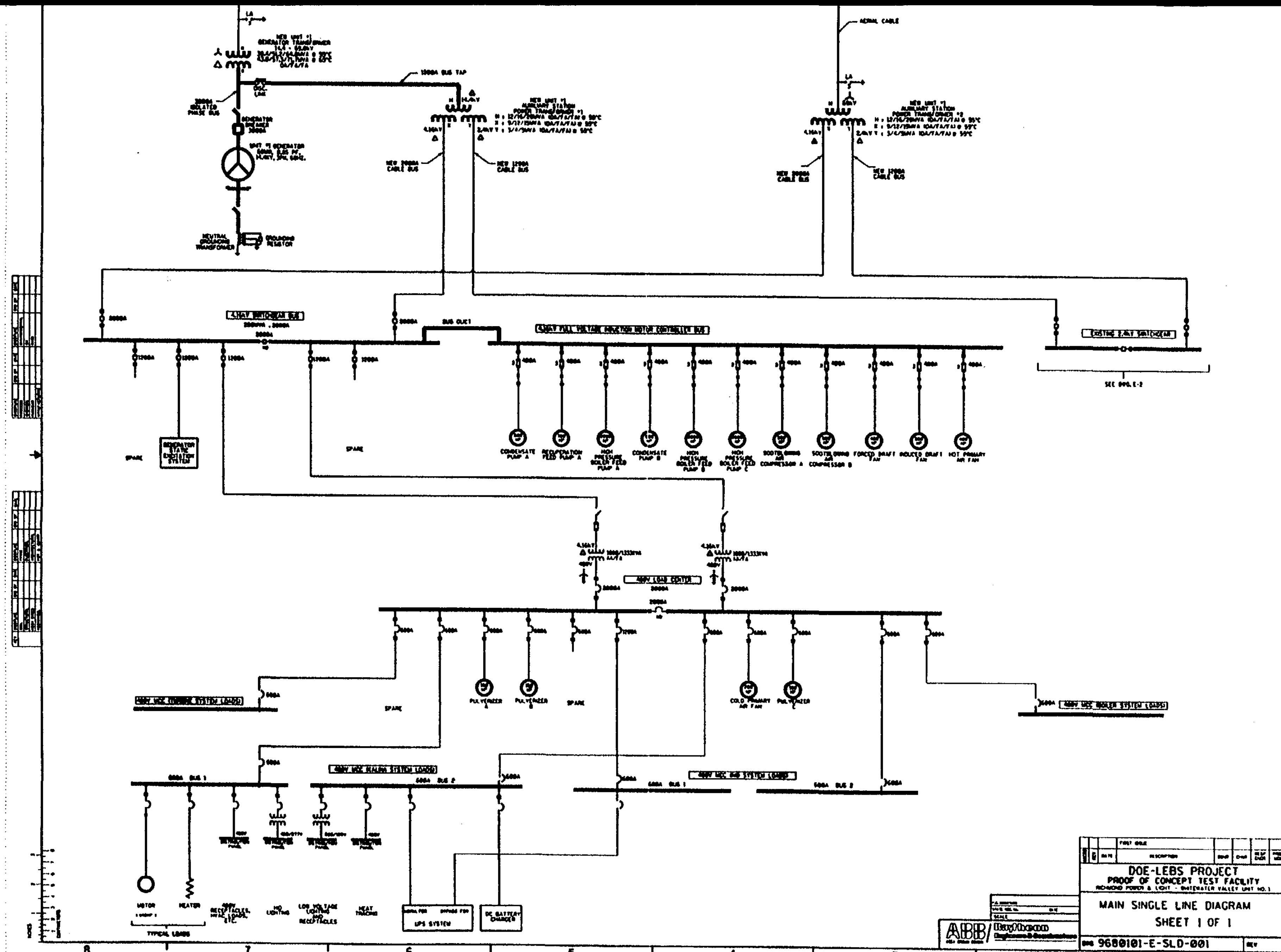
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3000A BUS TAP
SPARE
CONDENSATE PUMP A
CONDENSATE PUMP B
FORCED DRAFT FAN
INDUCED DRAFT FAN
HOT PRIMARY AIR FAN
480V LOAD CENTER
PULVERIZER
COLD PRIMARY AIR FAN
MOTOR
HEATER
HID LIGHTING
LOW VOLTAGE LIGHTING AND RECEPTACLES
HEAT TRACING
UPS SYSTEM
DC BATTERY CHARGER
TYPICAL LOADS
DOE-LEBS PROJECT
PROOF OF CONCEPT TEST FACILITY
MAIN SINGLE LINE DIAGRAM
SHEET 1 OF 1
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Fig. 9

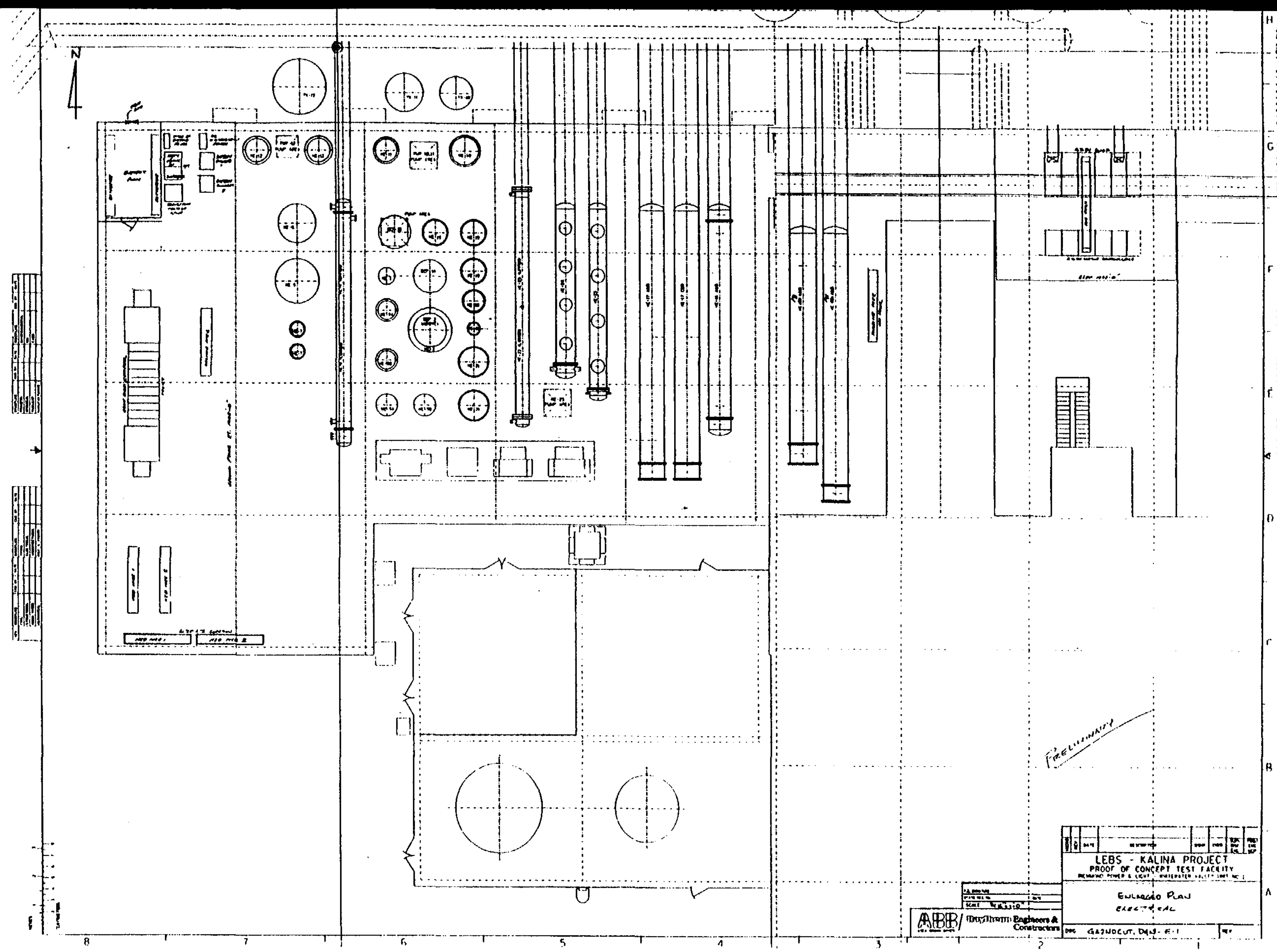
LEBS - KALINA PROJECT
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Fig. 10

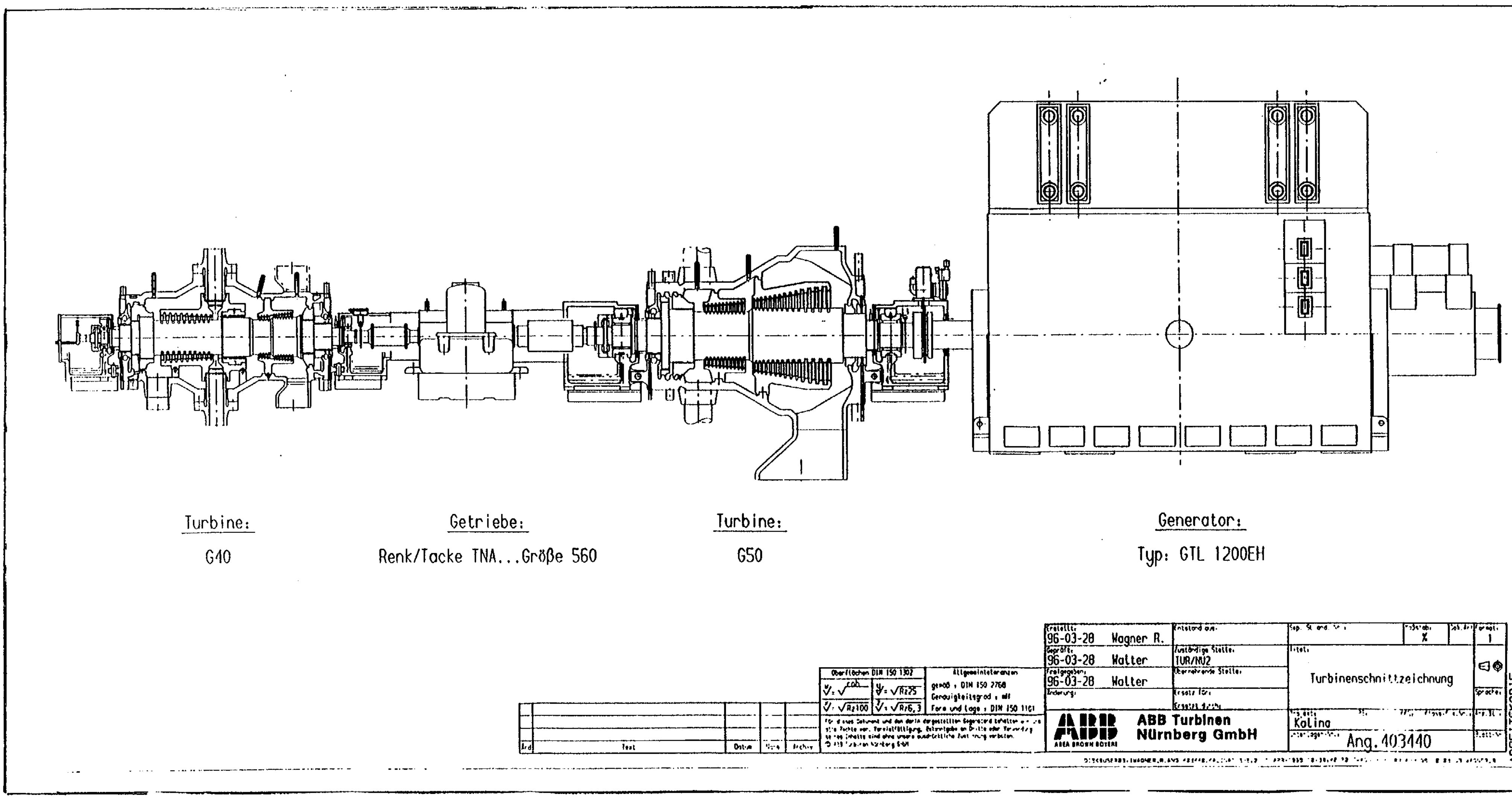
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Fig. 11

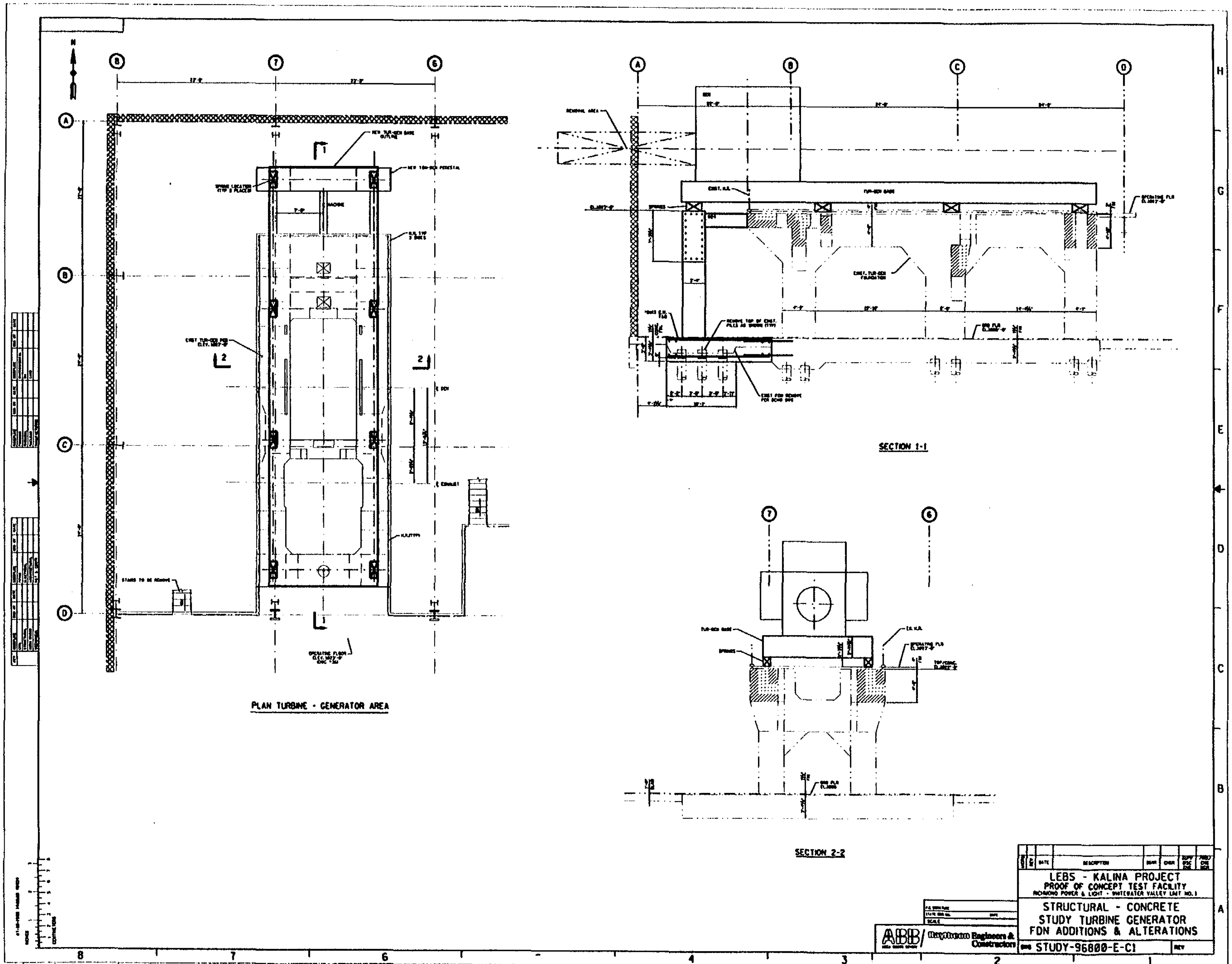


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Fig. 12

APPENDIX D - 12 pages

Technical Paper: "ABB's LEBS Activities - A Status Report"

# ABB'S LEBS ACTIVITIES - A STATUS REPORT


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First Joint Power & Fuel Systems Contractors Conference - July 96 Pittsburgh


CONTRACT NO. DE-AC22-92PC92159


## ABSTRACT


ABB Combustion Engineering, Inc. is one of three contractors executing Phases I, II and III of the Department of Energy project entitled Engineering Development of Advanced Coal-Fired Low-Emission Boiler Systems (LEBS). Phase I has been completed and Phase II is scheduled for completion on September 30, 1996. The following major activities are being carried out in parallel in Phase II and this paper is a status report on this work:

- In-furnace $NO_X$ reduction
- Catalytic filter optimization
- Add Kalina cycle to POCTF
- POCTF design and licensing

The in-furnace $NO_X$ reduction work has been completed and, therefore, a description of this work comprises the major part of this paper.


## INTRODUCTION

The primary objectives of the LEBS project are, using near-term technologies, to dramatically improve environmental performance of future coal-fired power plants while increasing their efficiency and maintaining the cost of electricity at or below current levels. The secondary objectives are to improve ash disposability, reduce waste generation and reduce air toxics emissions. The overall objective is expedited commercialization of the technologies developed. The major deliverables are a design data base and the preliminary design of a commercial generating unit (CGU).

Since the award of contracts in September 1992 the DOE has asked the contractors to strive for ever lower emissions and higher efficiency. In addition ABB, with the addition of the Kalina cycle, has set an even higher efficiency target. Today the targets are as follows:

| | | DOE Minimum Performance | DOE Preferred Performance | ABB's Targeted Performance |
|---|---|---|---|---|
| $SO_2$* | lb/MM Btu | 0.2 | 0.1 | 0.1 |
| $NO_X$ | lb/MM Btu | 0.2 | 0.1 | 0.1 |
| Particulates | lb/MM Btu | 0.015 | 0.01 | 0.005 |
| Efficiency (HHV, net), | % | 42 | 42 | 45 |

*3 lb S/MM Btu in the coal

Phase I consisted of selection of candidate technologies, creation of a preliminary 400 MWe CGU design and preparation of an RD&T Plan for Phases II and III. The Phase II work consists of: Component Optimization, POCTF Preliminary Design and Subsystem Testing. The four major Phase II activities are listed above in the ABSTRACT and are described below. (The work on in-furnace $NO_x$ reduction is the only one completed.)

**IN-FURNACE $NO_x$ REDUCTION**

**Introduction:** The most cost-effective method of reducing nitrogen oxide emissions when burning fossil fuels, such as coal, is through in-furnace $NO_x$ reduction processes. For the LEBS project, the DOE has specified the use of near-term technologies to provide for these overall emissions reductions. Based on technical and economic feasibility, advanced tangential firing was selected as the primary means of $NO_x$ emissions control for the ABB LEBS boiler design [1,2]. Specifically, ABB CE's TFS 2000™ firing system, which is a proven technology and commercially available, represents the technology selected as the basis for in-furnace $NO_x$ reduction. This firing system design has been demonstrated to provide $NO_x$ emissions of 0.2 pounds/MM Btu in prior laboratory and full scale, retrofit, utility boiler applications [3,4]. The objective of recent development work was to reduce this value to 0.1 lb/MM Btu.

Briefly, the TFS 2000™ firing system has been developed for minimum $NO_x$ emissions from pulverized coal fired boilers, accomplished by way of combustion techniques only. Specific features of this system include the use of concentric firing system (CFS) air nozzles, where the main windbox secondary air jets are introduced at a larger firing circle than the fuel jets; close-coupled overfire air (CCOFA) for improved carbon burnout; and multi-staged separated overfire air (SOFA) to provide for complete combustion while maintaining an optimum global stoichiometry history for $NO_x$ control. In addition, the TFS 2000™ firing system includes flame attachment coal nozzle tips for rapid fuel ignition and a pulverizer configured with a DYNAMIC™ Classifier to produce fine coal to minimize carbon losses under these staged combustion conditions.

Potential enhancements to the TFS 2000™ firing system focused on optimizing the introduction of the air and fuel within the primary windbox zone to provide additional horizontal and vertical staging. These enhancements were based on controlling the combustion of the coal in a more local sub-stoichiometric environment. That is, in addition to the global staging currently applied, improved $NO_x$ reduction was sought by controlling and optimizing the mixing of the fuel and air locally through vertical and horizontal staging techniques. As is the case with all in-furnace $NO_x$ control processes, it is necessary to operate the system in a manner which does not decrease $NO_x$ at the expense of reduced combustion efficiency. The objective of recent developmental work on the firing system was to reduce $NO_x$ emissions levels leaving the boiler to 0.1 pounds $NO_x$/MM Btu while maintaining carbon in ash at acceptably low levels (<5%) for high sulfur, mid-western and eastern bituminous coals.

The approach used in the development and evaluation of the various firing system concepts included an integrated approach of kinetic and computational modeling, small scale experimental testing in a Fundamental Scale Burner Facility (FSBF), and larger scale combustion testing in a Boiler Simulation Facility (BSF). Both modeling and experimental testing were applied to better understand the mechanisms governing in-furnace $NO_x$ reduction and to identify potential enhancements to the TFS 2000™ firing system. Results from this testing were used in the development of advanced low $NO_x$ firing systems which were evaluated in pilot scale combustion testing [5]. The pilot scale testing and evaluation of various advanced low $NO_x$ firing systems is described below.

**Pilot Scale Combustion Testing:** Pilot scale combustion testing of in-furnace $NO_x$ control systems was performed in ABB Power Plant Laboratories' BSF. The objective of this testing was to evaluate enhancements to the existing $NO_x$ control technologies for improved $NO_x$ emissions performance, while providing the necessary information for supporting the design of the $NO_x$ control subsystem for the LEBS Proof-of-Concept Test Facility (POCTF).

The BSF is a pilot scale test furnace, nominally rated at 50 MM Btu/hour (5 MWe) for coal firing, that reliably duplicates the combustion characteristics of a tangentially-fired utility boiler. All major aspects of a typical tangentially-fired utility boiler are duplicated in the BSF including a v-shaped hopper for bottom ash collection, the use of multiple burner elevations, and an arch with subsequent backpass convective "superheat," "reheat," and "economizer" surfaces. Selective refractory lining over atmospheric pressure "waterwalls" allows the matching of the residence time/temperature history of large scale utility boilers, including the horizontal furnace outlet plane (HFOP) gas temperature.

The BSF is fully instrumented to monitor the combustion process. Instruments for measuring coal feed rate, primary and individual secondary air mass flow rates, outlet emissions ($O_2$, $CO_2$, CO, $SO_2$, NO, and $NO_X$), and convective pass heat flux distribution are tied into a combined DCS/data acquisition system to allow for control and logging of these and other important operational parameters. For the subject testing, the BSF was operated in a tangentially-fired mode with levels of separated overfire air (SOFA). Prior laboratory test programs have shown that BSF test results can be reliably translated to the field for use in firing system design, and subsequent performance prediction [3].

Performance targets for the BSF combustion testing were consistent with those for the LEBS program; maximum $NO_X$ emissions of 0.1 pounds/MM Btu and carbon in the fly ash <5% for high sulfur, mid-western and eastern bituminous coals. In addition, the lower furnace heat absorption profiles and convective pass heat flux distribution were to remain similar to or improved over the existing system. The coal utilized during the BSF testing was the high sulfur, medium volatile, bituminous Viking coal from Montgomery, Indiana.

Prior to the initiation of $NO_X$ control subsystem testing, the firing system for the BSF was modified to take advantage of current and previous R&D project findings. First, ABB CE's Aerotip™ coal nozzle tip design was utilized as the base from which the BSF coal nozzles were constructed. The Aerotip™ design embodies improved aerodynamic features which support the test program need for a low $NO_X$ coal nozzle tip through its control over near field stoichiometry.

In addition to the incorporation of an Aerotip™ based coal nozzle tip, the main windboxes of the BSF were designed to accommodate a range of vertical and horizontal air and coal staging scenarios. The design of the secondary air nozzles was based on the need to maintain proper jet momenta, while having sufficient flexibility to test variations in vertical and horizontal air staging. In addition, excess coal nozzle capacity was incorporated to allow the testing of various coal staging scenarios, including two-corner coal firing. With this foundation, each of the "base" (*i.e.*, benchmark) firing system designs tested in the BSF, including the TFS 2000™ firing system, was able to incorporate the results of the prior chemical kinetic modeling and small scale (FSBF) combustion testing with respect to main windbox vertical air staging.

One goal of the BSF testing was to generate design data in support of achieving $NO_X$ emissions of 0.1 pounds/MM Btu through in-furnace firing system modifications (*i.e.*, prior to any post combustion process $NO_X$ reduction system). Toward this end, various "conventional" global air staging techniques were tested in order to benchmark their $NO_X$ reduction potential on the test fuel. This work included investigations of close-coupled overfire air (CCOFA), upper and lower (single) elevations of separated overfire air (SOFA), and an implementation of TFS 2000™ technology. All of the various overfire air configurations utilized the same main windbox arrangement, and all were performed with high fineness (90% - 200 mesh) coal grind, which is consistent with TFS 2000™ firing system design standards.

A summary of the results from testing various overfire air configurations with the test coal are given in Figure 1. As anticipated, the implementation of global air staging results in a significant reduction in furnace outlet $NO_X$ emissions. Beginning with $NO_X$ emissions of 0.52 pounds/MM Btu with a typical "baseline" (post-NSPS) firing system arrangement, $NO_X$ reductions continued to a low of 0.13 pounds/MM Btu for an "optimized" TFS 2000™ firing system arrangement (Note: similar 0.13 pounds/MM Btu outlet $NO_X$ emissions were obtained with the upper SOFA only, but this was at slightly degraded carbon in the fly ash performance). The "optimized" TFS 2000™ system incorporates improvements to the bulk stoichiometry history over the initial TFS 2000™ test, with identical main and overfire air windbox configurations. In all, a 75% reduction in $NO_X$ from baseline levels was achieved with the "optimized" TFS 2000™ system. As expected, carbon in the fly ash increased as the global staging was increased, but remained below the limit of 5%.

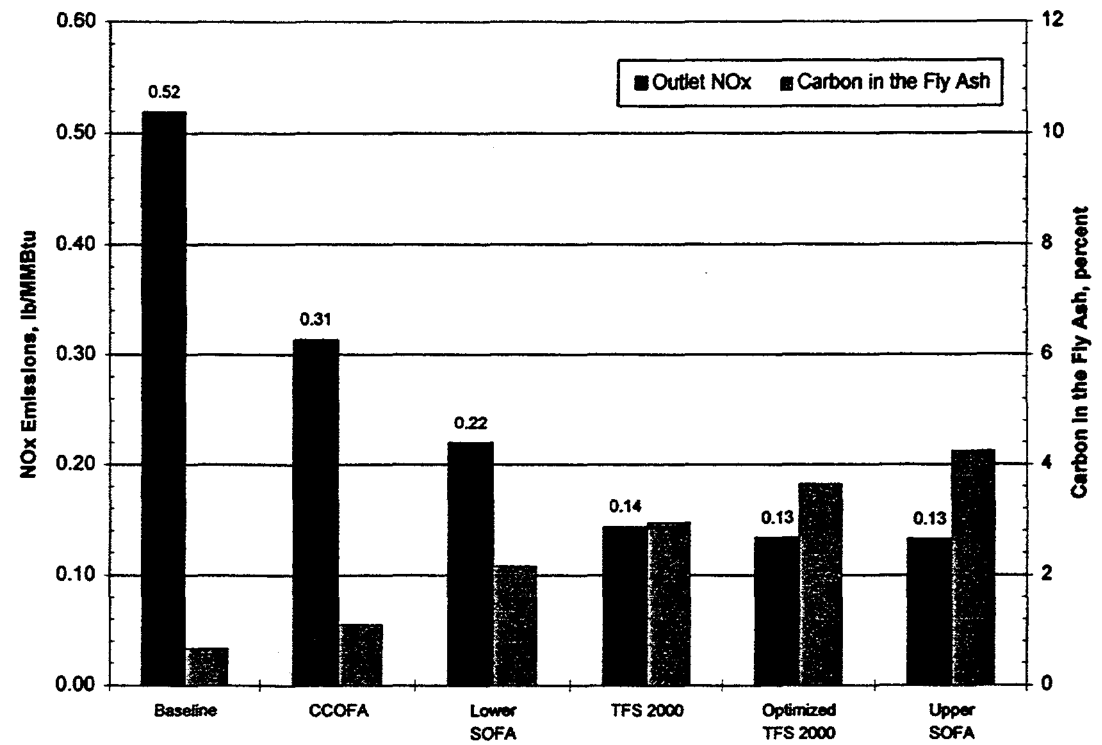


Figure 1 Global Staging

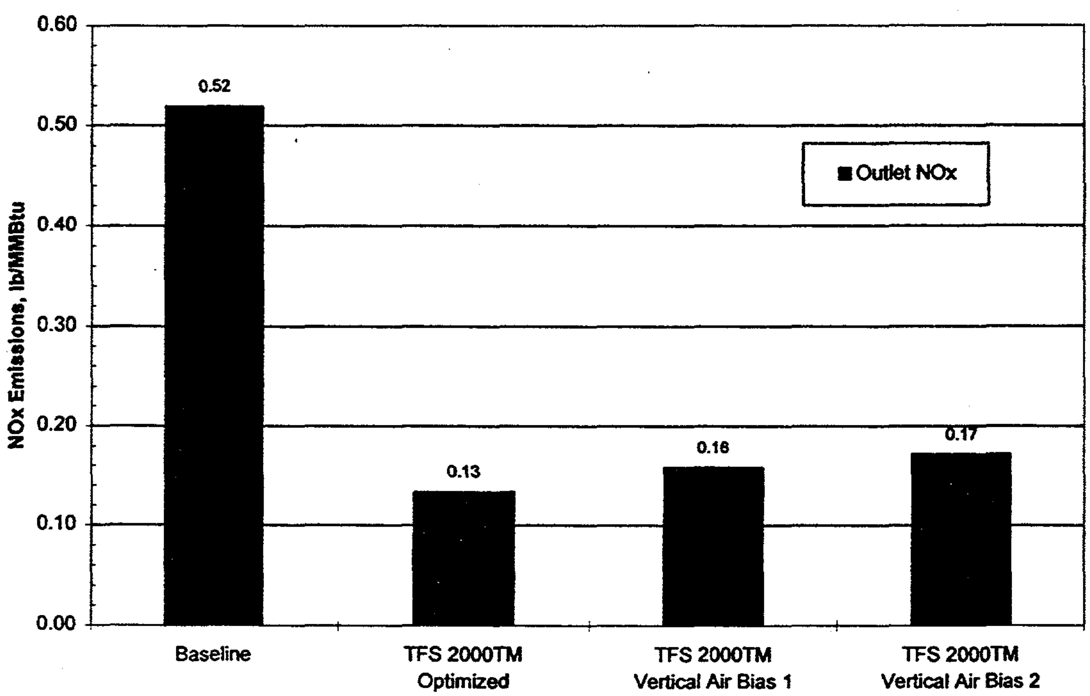


Figure 2 Effects of Vertical Staging on NOx

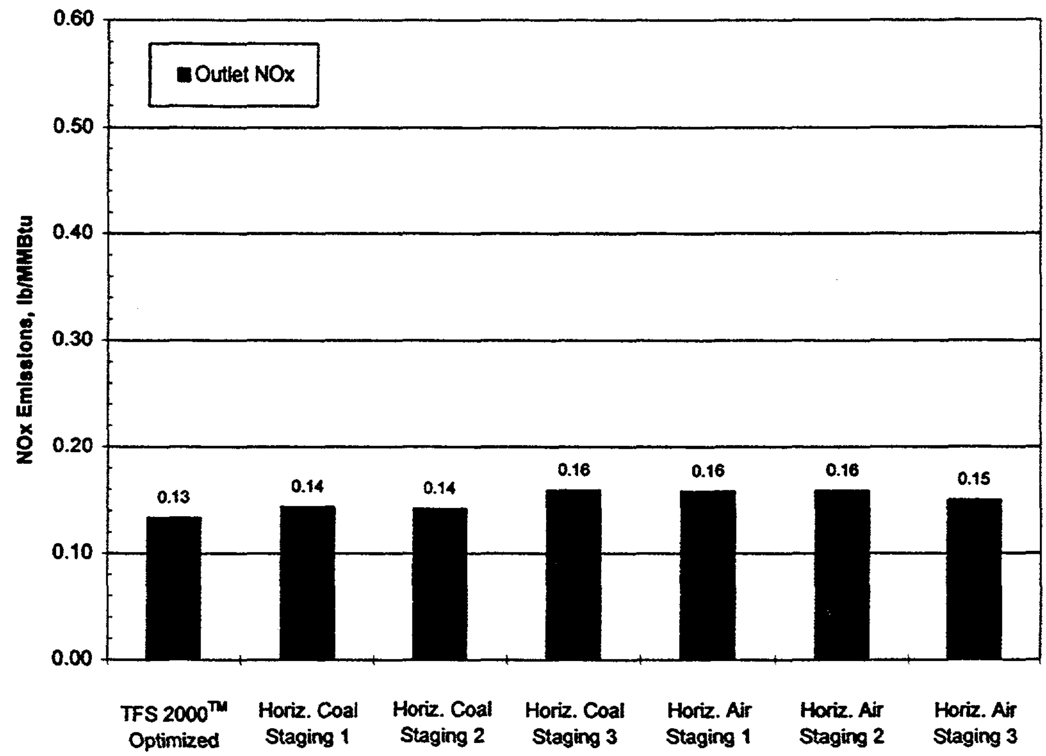


Figure 3 Effects of Horizontal Staging on NOx

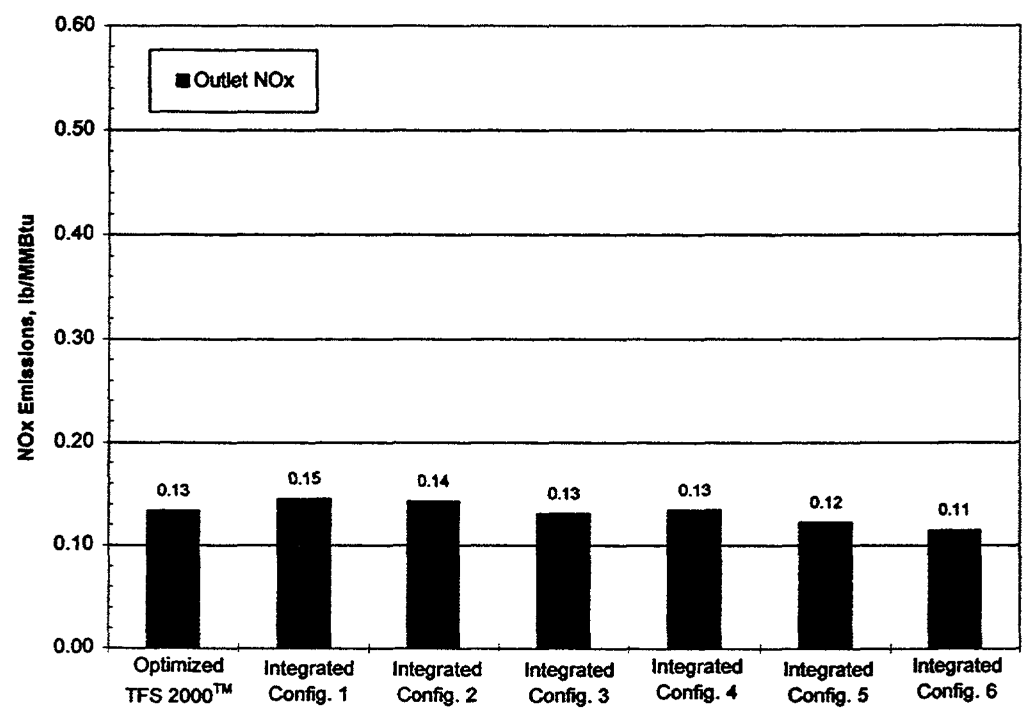


Figure 4 Effects of Integrated Staging on NOx

Having benchmarked the effects of global staging on firing system performance, both vertical and horizontal staging techniques within the main firing zone were subsequently tested to evaluate their effects on $NO_X$ performance. The objectives of this work were to confirm the results of prior main windbox vertical air staging work, and to further reduce outlet $NO_X$ emissions from the previously demonstrated "best" level of 0.13 pounds/MM Btu through the application of horizontal, and integrated vertical and horizontal main windbox staging techniques. As such, these methodologies were applied in concert with the "optimized" TFS 2000™ firing system, keeping the global stoichiometry history constant to allow meaningful comparisons.

First, vertical air staging within the main windbox was independently varied to demonstrate its effect on $NO_X$ formation at this large pilot scale. Results from this testing, given in Figure 2, show that significant variation in $NO_X$ emissions occur as main windbox vertical air staging is changed. In this case variations to the vertical air staging produced a +/- 13% deviation in outlet $NO_X$ about the mean. This result confirms that the main windbox vertical stoichiometry history is an important contributor to overall $NO_X$ formation, even with significant levels of global air staging. Overall, $NO_X$ emissions increased when variations to the main windbox vertical stoichiometry build-up were applied to the previously "optimized" TFS 2000™ arrangement. This result is, however, expected since the "optimized" TFS 2000™ system incorporates the results of prior chemical kinetic modeling and small scale combustion test vertical air staging work into the configuration of its main windbox as noted above.

Next, horizontal staging, used to control the horizontal "build-up" of stoichiometry (corner to corner) within the main burner zone, was evaluated. This was accomplished by biasing the fuel and air between one or more of the four corners. Tested subsets of this technique are two corner firing, where all of the air and fuel are injected through two of four corners in a tangential arrangement, and opposed corner firing where the coal is injected from two corners, and the air from the remaining two. In general, independent implementation of horizontal staging techniques resulted in neutral to degraded $NO_X$ emissions performance over that of the "optimized" TFS 2000™ firing system during the subject testing. This is seen in Figure 3, which shows the effect of independent variation of either fuel or air (horizontal staging) on overall $NO_X$ emissions performance. These results demonstrate that, similar to the prior vertical staging experiments, outlet $NO_X$ emissions can be affected by horizontal fuel and air distributions. However, these results also demonstrate that the global time - stoichiometry history (*i.e.*, the TFS 2000™ stoichiometry profile) dominates the $NO_X$ formation and reduction processes at these levels of global air staging.

Finally, several configurations which applied integrated vertical and horizontal staging techniques as a means of "optimizing" the stoichiometry of combustion within the main windbox were evaluated. Integrated vertical and horizontally staged firing systems were extensively evaluated using CFD modeling prior to the BSF tests. In contrast to their independent performance, Figure 4 shows that when suitably combined, an integrated vertical and horizontal staging strategy offers a small, but consistent improvement to the $NO_X$ emissions performance of the optimized TFS 2000™ system. At a $NO_X$ emission level of 0.11 pounds/MM Btu, the "best" integrated system ("Integrated Config. 6") produced a greater than 10% reduction in $NO_X$ over the previously "optimized" TFS 2000™ system. Carbon loss results (not shown) were also similar for the two firing systems.

Additional pilot scale testing of potential $NO_X$ control subsystems in the BSF has been recently completed and results are being analyzed. The objective of this testing was to confirm the performance of the integrated vertical and horizontal staging technique, focusing on the repeatability of the present test results, while generating design information for this and other promising firing system concepts for eventual full scale utility boiler application.

## CATALYTIC FILTER OPTIMIZATION

<u>Introduction</u>: The principal goal of the Catalytic Filter Optimization activities is the acquisition of initial field test data, which will be used for a larger field demonstration. These activities include the determination of feasible and reasonable operating conditions for the catalytic filter system. Data collected through testing will focus on particulate and $NO_X$ removal efficiencies as well as filter draft loss.

The goals of this task are listed below in order of priority. It is desirable that these goals be achieved simultaneously.

- Particulate emissions of less than 0.005 lb/MMBtu
- Maximum filter clean-side draft loss of 8 inches w.g. at 4 ft/min at 775°F
- Operation with a Filter Face Velocity (FFV) of at least 4 ft/min at 650°F
- Minimum of 80% $NO_x$ removal efficiency
- Ammonia slip of less than 15 ppm

Information gained from demonstration and evaluation will address the following issues:

- Confirm filter particulate removal efficiency.
- Determine the tubesheet differential pressure (filter draft loss) as a function of face velocity, cleaning cycle characteristics, operating time, and other parameters.
- Determine the $NO_x$ reduction efficiency as a function of flue gas composition ($NO_x$ inlet concentration, $NH_3$ stoichiometry, particulate removal), and flue gas temperature. Of further interest is the determination of the requirements to maintain the catalytic conversion efficiency.

Approach: The approach used is to test the Catalytic Filter System with four filter modules on a 100 ACFM (165 $m^3$/hr) slipstream at Richmond Power & Light's Whitewater Valley Station Unit 2, a 66 MWe pulverized coal-fired boiler. CeraMem manufactured the ceramic filter modules and Engelhard applied the $NO_x$ reduction catalyst.

A slipstream unit was constructed and installed at the Richmond site, taking flue gas off the boiler at the economizer section, processing the gas to remove particulate and $NO_x$, and returning the gas to the air heater. The test system was installed at the site February and March of this year, and operation started immediately upon completion of installation. At this writing, an initial 500-hour test has been concluded, in which both particulate removal and $NO_x$ reduction were investigated.

Preliminary Results: *The tubesheet differential pressure* (filter draft loss) is considered an essential element to the success and applicability of the catalytic filter to the LEBS Commercial Generating Unit (CGU) design. An excessive tubesheet differential pressure would require excessive fan power to move the flue gas through the system for processing. For the first 500-hour test, the initial tubesheet differential pressure was approximately 16 inches w.g. (FFV=4 ft/min, T= 650°F).

The filter permeance, a parameter inversely proportional to tubesheet differential pressure and independent of filter face velocity and process temperature, decreased through the first 150 hours of operation, as shown in Figure 5. This decrease indicated that the filter tubesheet differential pressure increased at constant process conditions, an effect that is typical of all ceramic particulate filters. This decrease in permeance or increase in tubesheet differential pressure is caused by the smaller particulate (less than 0.5μ diameter) becoming permanently lodged in the filter substrate. For all ceramic particulate filters, the filter permeance should stabilize at some point, indicating that essentially the pores that are able to become "plugged" have been, and that the filter is being cleaned efficiently. At this point, the tubesheet differential pressure will remain constant at constant process conditions. In the case of the initial 500-hour test, the tubesheet differential pressure rose to approximately 23-24 inches w.g. (FFV=4, T=650°F) after approximately 200 hours of operation and was stable for the remainder of the test.

Upon conclusion of the 500-hour test, the system was opened and the filter modules were inspected. Visual inspection showed that the filters were being cleaned effectively, with no particulate buildup being detected and no plugged channels being found.

Subsequent analysis of the catalytic filters indicate that catalyst addition was responsible for approximately 75 % of the tubesheet differential pressure.

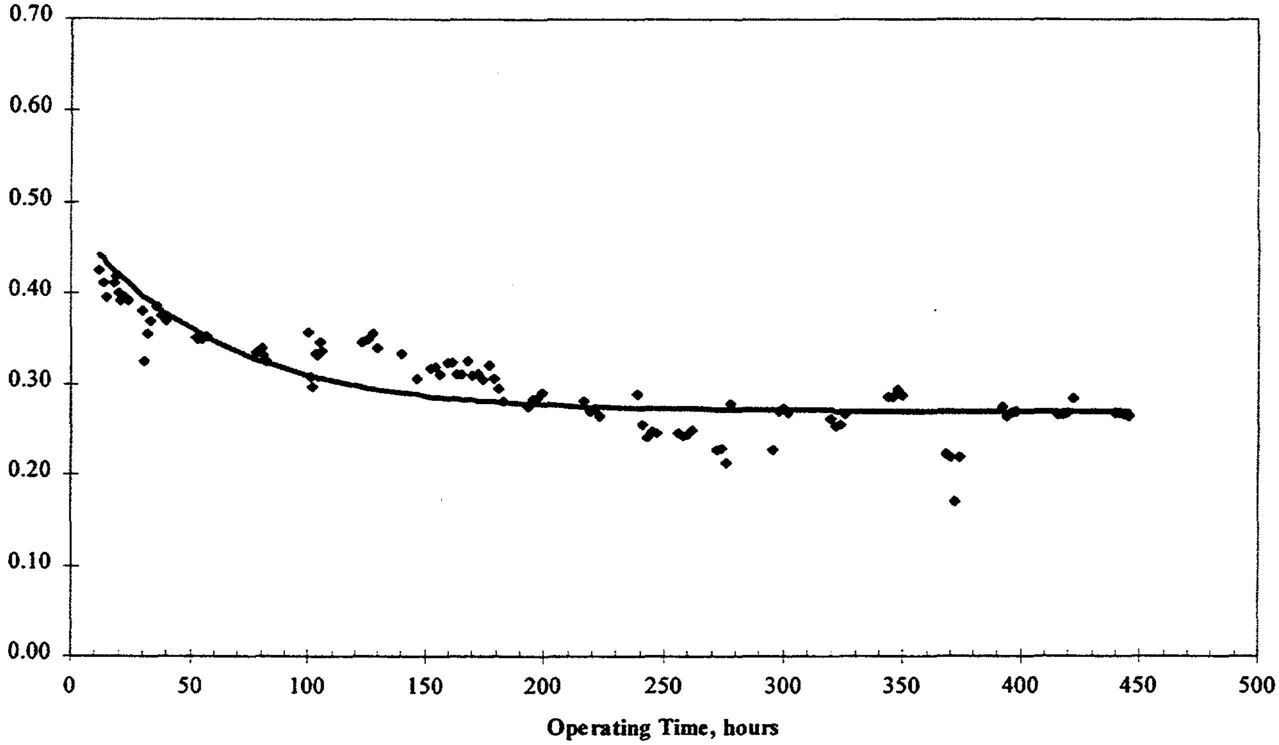


**Figure 5 - Filter Permeance vs. Operating Time**

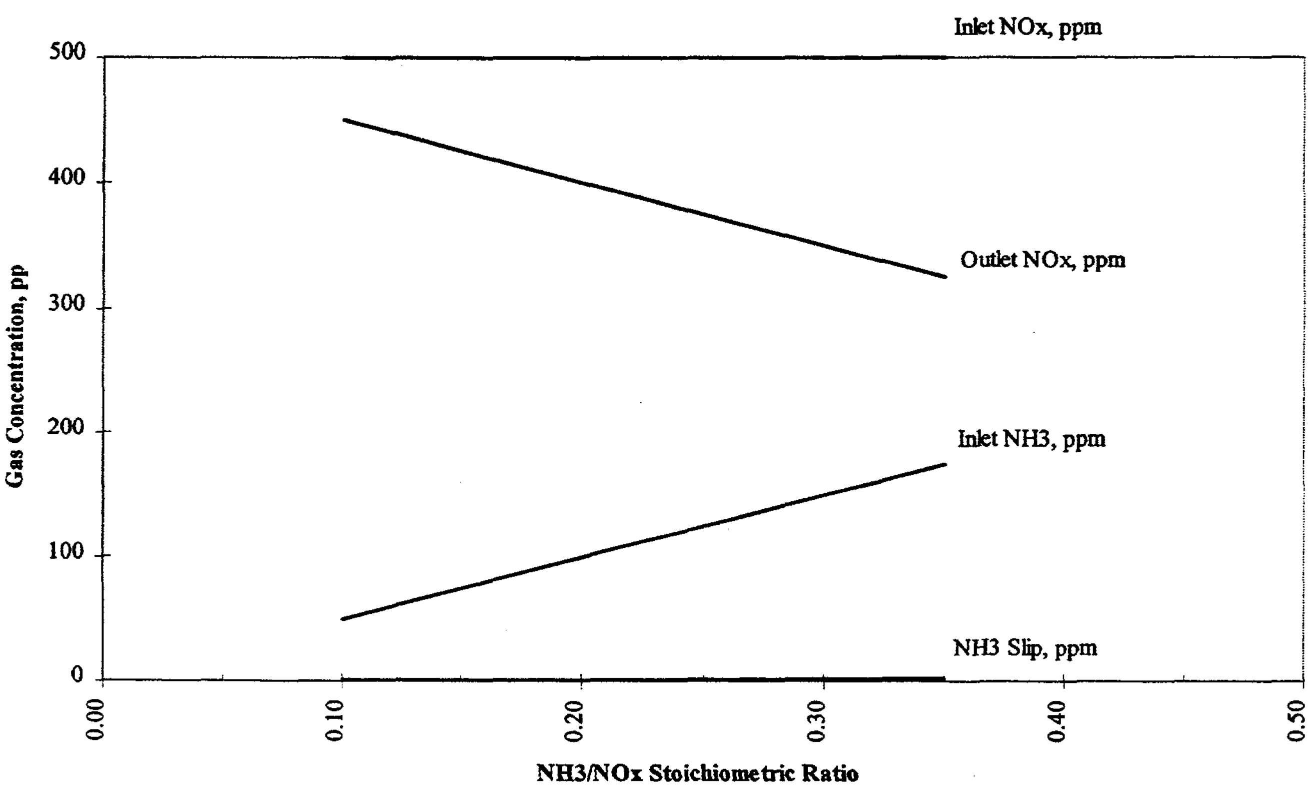


**Figure 6 - NOx Reduction**

*Particulate removal* for this filter system was expected to be near absolute. In previous testing of the filter system at ABB's corporate laboratory in Baden, Switzerland, outlet emissions from the filter could not be detected using a laser light-scattering measurement system, indicating that removal efficiency exceeded 99.99994%.

In the 500-hour test, two outlet particulate samples were taken, with results indicating a removal efficiency of 99.93% which is below the expected value.

Upon completion of the 500-hour test, the unit was opened and the tubesheet and vessel inspected. Lack of particulate matter on the "clean-side" of the tubesheet, particularly in cracks and crevices, tends to indicate that particulate matter was not passing through the filters and that the sampling results were reflective of material that had been left in the ducts when the system was being bypassed.

*$NO_X$ Reduction Efficiency* testing was initiated after approximately 350 hours of operation. Ammonia was injected into the system to facilitate the $NO_X$ reduction reaction. Inlet and outlet ammonia sampling was conducted to quantify ammonia injection rates and ammonia slip, while $NO_X$ inlet and outlet concentrations were determined using two ThermoElectron Model 10 $NO_X$ CEMs. Due to vendor problems that are beyond the scope of the paper, maximum injection stoichiometry was limited to 0.4 (maximum ammonia concentration in the inlet flue gas was approximately 200 ppm).

Preliminary results indicate that the catalyst made efficient use of the ammonia, as shown in Figure 6. The ammonia was fully accounted for in the $NO_X$ reduction reaction, and sampling and analysis found less than 3 ppm in the outlet flue gas in all samples.

Future Tests: It is unlikely that an advancement in catalyst deposition technology will be made that will achieve an initial tubesheet pressure differential of less than 8 inches w.g. within the 100 ACFM Test time frame. A second 500-hour test is presently under way to gather engineering data on the performance of a non-catalytic filter system. Catalyst development is continuing in a parallel program, with the hope of being able to achieve project goals by completion of Phase II.

## POCTF DESIGN AND LICENSING WITH A KALINA CYCLE

Introduction: The centerpiece of the LEBS project is Phase IV which will undertake the design, construction and test operation of a proof-of-concept test facility (POCTF). These final-phase activities will provide the design and operating database critical to commercialization of the LEBS technologies. The current project plans are that only one of the three original LEBS teams, with their respective technologies, will be selected to implement Phase IV. The on-going Phase II and III tasks, however, include the precursor planning activities leading up to down-selection and Phase IV initiation. At present, the ABB LEBS team is developing a site-specific preliminary design for their POCTF, and has project licensing in progress.

Project Description: ABB has been fortunate in obtaining a commitment for an outstanding host site for their POCTF. Richmond (Indiana) Power & Light Co. (RP&L) has offered to host the project at their Whitewater Valley station. RP&L has a history of successful involvement in technology demonstration programs, including one of the earliest low $NO_X$ burner installations, a LIMB installation, and a Clean Coal Technology project.

The Whitewater Valley plant is composed of two coal-fired, non-reheat units, with nominal ratings of 33 MWe (unit 1) and 66 MWe (unit 2). Unit 1 will be modified to accept the LEBS technology package. This unit is approximately 40 years old, and incorporates a 900F/900 psig steam cycle with a steam capacity of 325,000 lb/hr. The POCTF project will involve a major restructuring of the unit, that entails the replacement of the complete power system (boiler, turbine-generator, feedwater heaters, power piping) with a new Kalina-based power system, and addition of the LEBS flue gas cleanup system. The project will use the plant infrastructure to the maximum extent practical, including coal handling, heat rejection, ash handling, powerhouse structures, and auxiliary systems. Although the project is being implemented as a test facility, RP&L intends to use the unit for long-term production service following completion of the LEBS project. This criterion, therefore, has a dominant effect on specification and design of the equipment and the facility.

The approach taken in establishing the size of the modified unit has been to maximize its generating capacity, consistent with making maximum use of existing plant infrastructure. Key plant performance parameters are summarized in Table I.

Table I - UNIT 1 PERFORMANCE PARAMETERS
(Preliminary)

| Thermal | | Existing | POCTF | Change |
|---|---|---|---|---|
| Coal Heat Input | MM Btu/hr | 400 | 440 | + 10% |
| Cooling Tower Load | MM Btu/hr | 216 | 215 | |
| Generator Output | MWe | 35.6 | 54.6 | |
| Auxiliary Load | MWe | 2.2 | 6.7 | |
| Net Unit Generation | MWe | 33.4 | 47.9 | + 43% |
| Net Unit Heat Rate | Btu/kWh | 12,000 | 9,186 | - 23% |
| Environmental | | | | |
| $SO_2$ | lb/MM Btu | 6.0 / 1.6(*) | 0.1 to 0.2 | / - 90% |
| $NO_X$ | lb/MM Btu | - / 0.5(*) | 0.1 to 0.2 | / - 70% |
| Particulates | lb/MM Btu | 0.19 / 0.19(*) | 0.01 | / - 95% |

(*) pre/post Phase II Clean Air Act Amendments (2000)

By leveraging the significant improvement in heat rate offered by the Kalina cycle with a modest 10% increase in coal heat input, the unit output will be increased a substantial 43% to about 48 MWe, with a corresponding 23% decrease in heat rate. At the projected net unit heat rate of about 9,200 Btu/kWh, the modified Whitewater Valley unit 1 will be the most efficient coal-fired unit of its size in the U.S. The planned project, in fact, compares favorably to the best coal-fired unit heat rate reported in the USA in 1994 of 8,889 Btu/kWh (annual average) for a 660 MW supercritical unit.

Equipment: To date, an initial feasibility study for the project has been completed, and the preliminary design is in progress. Highlights of this on-going project conceptualization are described below.

Because the Kalina cycle optimizes at different thermodynamic conditions than a steam cycle, and because of the change in working fluid and the increase in generating capacity, the complete steam side of the power cycle is to be removed and replaced. These systems include the boiler and auxiliaries, turbine-generator and auxiliaries, condenser, condensate system and feedwater system. The size of the unit has been selected such that the new vapor generator will fit in the existing boiler support-steel cavity, and the new turbine-generator will fit the existing turbine pedestal (after pedestal modification). The fact that the Kalina cycle regenerates substantially more heat than a steam cycle results in a significant increase in the number of regenerative heaters, such that a turbine hall addition will be required to house this new equipment.

The vapor generator, or boiler, design for the POCTF is a single reheat, drum type with pumped circulation for cooling furnace wall evaporative tubes. The Kalina cycle, with its higher rate of heat regeneration, requires less evaporation but more superheater and reheater duty in the vapor generator. Thus, in addition to pendant and horizontal superheater and reheater surfaces, in the preliminary design portions of the upper furnace walls are used for superheating and reheating the working fluid. The design of these sections is the same as conventional radiant wall reheater designs. The vapor generator looks very much like a large utility unit designed for a Rankine cycle.

Turbine design performance for a Rankine or Kalina cycle is very similar. Ammonia has a molecular weight very close to that of pure water, (17 vs. 18). This allows the use of current designs for turbine blading and turbine shell to be used in a Kalina cycle. One major difference in the turbine, when used in a Kalina cycle, is that the turbine is changed to a back pressure configuration. In doing so, there is no need for the large low pressure section and vacuum system which are required in the Rankine cycle. This provides a capital cost saving as well as improved system efficiency.

In addition, the inclusion of the LEBS flue gas emissions control features dictates removal of the gas side power cycle systems. The replacement systems will include the low $NO_X$ firing technology described previously, a new draft system, and a flue gas cleanup system. At present, two alternative processes are being evaluated for flue gas cleanup: the $SNO_X$™ hot process and an advanced dry-scrubbing process.

Control requirements associated with the Kalina power cycle, and the fact that unit 1 still has its original control system, dictate that the project will include installation of a new unit-wide distributed control system. The increase in auxiliary power consumption associated with the modified unit also requires that the station service transformers for unit 1 (unit auxiliary and startup) be replaced with larger capacity units, and substantial new power distribution capability be added.

<u>Licensing</u>: A licensing plan and schedule have been developed for the project that has identified the need to obtain twelve individual environmental/safety permits and approvals. As indicated in Table I, the project will result in large reductions of all the regulated air emissions from unit 1. Thus, approvals for the air permits are expected to be relatively straight forward. Unique to this power project, however, is the significant ammonia inventory required for operation of the Kalina cycle. The presence of this material on site will require the development of plans to deal with a potential accidental ammonia release.

The licensing schedule is based on obtaining all approvals prior to the planned start date for Phase IV. At present, contact has been established with the Indiana Department of Environmental Management (IDEM). IDEM has been thoroughly briefed on the proposed project, and preparation of the long-lead permit applications is in progress.

## CONCLUSIONS AND FUTURE WORK

Testing of the low-$NO_X$ firing system has been completed. The work remaining is analysis of data from the second week of testing in the BSF. The $NO_X$ emission target of 0.1 lb/MM Btu with <5% carbon in the fly ash was achieved in the BSF (actually 0.11 lb). However, at this time it cannot be predicted with certainty that 0.1 lb/MM Btu will be achieved in commercial size systems. There presently is no further LEBS firing system development work planned prior to construction of the POCTF.

The preliminary results of the catalytic filter field testing were very encouraging regarding particulate emissions and $NO_X$ reduction. However, measured gas draft loss was excessive. Since approximately 75% of the draft loss is attributed to the catalyst, testing will continue with a non-catalytic filter system while catalyst deposition technology is reviewed. Also, since it is possible that the catalytic filter draft loss situation may not be resolved within the POCTF schedule, an alternative technology will be evaluated.

The POCTF design work was rescheduled to allow time to design the Kalina cycle components and to integrate them into the existing facilities at the host site. That work is essentially complete and plant design and licensing work has resumed and will be completed within the project schedule.

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